NATIONAL ENERGY TECHNOLOGY LABORATORY

Research Portfolio Accomplishment Report

Unconventional Oil & Gas Resources: Subsurface Geology and Engineering

DOE/NETL-2015/1691
Activity 4003.200.03

U.S. DEPARTMENT OF ENERGY

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Research Portfolio Accomplishment Report

Unconventional Oil & Gas Resources: Subsurface Geology and Engineering

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The project data, photos, and graphics provided in the project summaries that follow the introduction come from available project documentation—including final reports, fact sheets, NETL project summaries, RPSEA monthly reports, and project websites—and through the generous assistance of Principal Investigators, industry partners, RPSEA, and NETL staff.

Unconventional Oil & Gas Resources:

Subsurface Geology and Engineering

Executive Summary

Subsurface geological and engineering research carried out by the Department of Energy's (DOE) Office of Fossil Energy over the past decade has accomplished some significant results that are enhancing our ability to produce natural gas and oil from reservoirs considered "unconventional" due to their low permeability (tight sands and shales). Just a few of these accomplishments include **new models** for understanding and predicting well performance, **public data sets** characterizing emerging shale plays for use by producers, **cutting edge laboratory experiments** that shed new light on how fluids flow through pores that are only nanometers wide (a nanometer is a billionth of a meter), and **groundbreaking field experiments** that help publicize information about hydraulic fracturing technologies for a wide range of stakeholders.

> ***Subsurface Geology and Engineering Research is creating the new models, public data sets, and experiments that are transforming shale and other gas and oil production.***

Shale and other "unconventional" natural gas-bearing and oil-bearing rocks present unique challenges to producers. Selecting the best well site requires a thorough understanding of the natural fracture systems present in the rocks as well as how fluid is stored in these fracture systems and the rock matrix. Strategies for developing these resources require technologies that maximize the amount of reservoir accessed (e.g., horizontal drilling), maximize the volume of reservoir rock connected to the borehole (e.g., multiple stage, large volume hydraulic fracturing), and minimize both the environmental impacts (e.g., multi-well pad drilling) and cost of development. Research efforts supported by DOE's Office of Fossil Energy and others from the 1970s through 2000s helped to accelerate development of many of these technologies. The success of industry in extending and applying these technologies has resulted in the fact that today "unconventional" resources are now responsible for the majority of our nation's natural gas production and much of its oil production.

The Office of Fossil Energy through the National Energy Technology Laboratory (NETL) continues the research into unconventional oil and gas resources that began in the late 1970s. This effort includes research funded through annual appropriations under the Environmentally Prudent Development Program, research initiated through Section 999 of the Energy Policy Act of 2005 (Section 999), aka the Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Research Program, and research conducted through NETL's Office of Research and Development. A focus of this research has been developing technologies to reduce or mitigate environmental impacts associated with Unconventional Oil and Gas production.

The Environmentally Prudent Development (EPD) Program focuses on advancing national research goals through science and technology development conducted in partnership with academia, other federal agencies, national laboratories, and the private sector. The research program is aligned with the research priorities as described in "Federal Multi-agency Collaboration on Unconventional Oil and Gas Research" that was jointly released by the DOE, the USGS, and the EPA in July 2014. The goal of the EPD Program is to support the prudent development of the nation's shale gas, tight gas, and tight oil resources (collectively referred to as "Unconventional Oil and Gas (UOG) resources" by 1) increasing our understanding of the varied nature of subsurface processes acting during development, 2) enabling the more efficient utilization of resources via technology that allows greater recovery from fewer, less impactful, wells, and 3) providing objective science and technological solutions that mitigate the environmental risks associated with UOG development.

Overcoming the barriers to achieving this goal requires research directed towards solving subsurface geological and engineering problems. More specifically, the R&D must: (1) improve our understanding of the basic petrophysics and geomechanics of UOG reservoirs; (2) improve our understanding of how hydraulic fractures are created deep within the subsurface and the fracture geometries that result from specific treatment designs; (3) develop better methods for predicting, monitoring, and optimizing well performance; and (4) create and test new tools and methods for reducing or mitigating the environmental impacts (air, water, land) associated with UOG development.

Among the many accomplishments highlighted in the following pages are examples of how DOE partnered with industry and academia and:

- Determined that the shale formations of Alabama contain a total original gas in place of 826 Tcf, with an estimated technically recoverable resource of between 70 and 139 Tcf;
- Discovered that there is an optimum time for refracturing wells using data from 300 tight gas wells in the Codell formation of the Wattenberg field in Colorado, including 170 refractured wells;
- Discovered that the angularity of nonplanar and nonorthogonal hydraulic fractures can significantly affect reservoir performance;
- Analyzed over thirty fracturing stages in two horizontal wells using downhole microseismic imaging and production logging to reveal more efficient resource recovery from variable rate stimulation as compared with conventional fracturing;
- Carried out an integrated geologic and geophysical study of the Bakken petroleum system in the Williston basin of North Dakota and Montana and provided operators with a web-accessible database of Bakken data to help them optimize production from this important oil resource; and
- Carefully monitored the hydraulic fracturing of six horizontal Marcellus Shale gas wells using microseismic monitoring, chemical and isotopic analysis of produced fluids, tracer analysis, and pressure monitoring to determine that hydraulic fractures did not extend upwards into shallower gas producing zones and that no detectable migration of fluids had occurred during or within one year of hydraulic fracturing.

Additional details on these and other accomplishments are provided in the sections that follow in this report.

Introduction

The goal of the EPD Program is to support the prudent development of the nation's shale gas, tight gas, and tight oil resources by 1) increasing our understanding of the varied nature of subsurface processes acting during development, 2) enabling the more efficient utilization of resources via technology that allows greater recovery from fewer, less impactful, wells, and 3) providing objective science and technological solutions that mitigate the environmental risks associated with UOG development.

The research projects within the research portfolio have been categorized into "bins" of projects that are focused on a common topic. This Research Portfolio Accomplishment Report provides a snapshot of accomplishments to-date for active and completed projects in the portfolio that are grouped into the Subsurface Geology and Engineering Research bin. The first section of this report provides an overview of the bin. Project summaries for each of the projects are provided in the pages that follow.

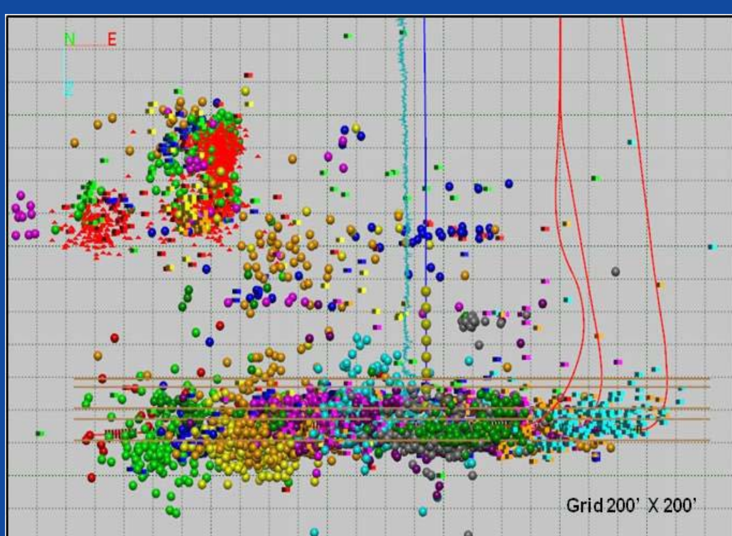
What is subsurface geology and engineering research?

Subsurface geology and engineering research combines expertise from many fields—including structural and stratigraphic geology, geophysics, geomechanics, geochemistry, remote sensing and imaging, drilling and well completion engineering—to collect and analyze datasets, improve existing modeling techniques, and build new tools that will improve the efficiency and reduce the environmental impact of the unconventional oil and gas production process.

The major areas of focus in this Unconventional Oil and Gas Resources research bin include:

- Identifying, quantifying, and reducing the risks of environmental impacts from UOG development,
- Optimizing recovery efficiency in ways that help to reduce environmental impact,
- Improving our understanding of unconventional gas and oil resource generation, reservoir rock properties and the physics of well production behavior,
- Characterizing and assessing emerging unconventional resource plays and disseminating the information to a wide

New Understanding of the Risks Posed by Hydraulic Fracturing to Water Supplies



DOE monitored the hydraulic fracturing of six horizontal Marcellus Shale gas wells in Greene County, PA using microseismics, chemical and isotopic analysis of produced gas and water, tracer analysis, and pressure measurements. The results illustrated that hydraulic fractures did not extend upwards to shallower gas producing zones and that no detectable migration of gas or aqueous fluids occurred during or after hydraulic fracturing.

Additional details on this project are available in the project summaries, p. 59.

Image caption: **East/west depth section looking north that shows the vertical distribution of microseismic events located during the hydraulic fracturing of horizontal Marcellus Shale Wells A, B, and C (Stage 1 only) in Greene County, Pennsylvania. Gold spheres on blue line depict geophone positions. Spheres represent various Well A stages, Squares represent various Well B stages, and Triangles represents Well C Stage 1 only.**

audience of stakeholders, and
- Developing new models for predicting and optimizing well and reservoir performance.

Why conduct this research?

Shale and other "unconventional" natural gas-bearing and oil-bearing rocks present unique challenges to producers due to their ultra-low porosity and permeability, the complexity of the natural fracture system, and many unknown or not well-understood fluid rock and fluid-fluid interactions. Subsurface geology and engineering research is providing the fundamental understanding, complex datasets, innovative modeling tools, and advances in technology needed to optimize the recovery of unconventional resources while minimizing environmental impacts. Improvements in our understanding of the resource and optimal methods for producing it will be vital to achieve a balance between recovery optimization and environmental impact minimization that the program is seeking to accomplish. Accurate models and new technology and data drive decision-making by researchers and industry. Development of unconventional resources still involves some risk—including potential financial, environmental, and human safety—but the subsurface geology and engineering research being conducted through DOE strives to mitigate these risks. Subsurface geology and engineering researchers are collecting and analyzing datasets, building and testing improved models, and enhancing the tools and techniques that will ensure sustainable natural gas and oil production into the future. These research efforts require a combination of field monitoring, laboratory experiments, data mining, and modeling activities.

Unconventional oil and gas resources will play a vital role in our long-term energy strategy. As conventional and unconventional sources are depleted, scientists and industry will encounter new challenges in finding ways to maximize recovery of the resource in place while protecting the environment. Industry will rely on the understanding, methods, and tools generated by ongoing subsurface geology and engineering research to meet these challenges.

Accomplishments

Accomplishments from subsurface geology and engineering research projects include new datasets, new models, prototypes, comprehensive reports, and other insights that provide valuable contributions to industry understanding. The following selected examples of accomplishments recorded by these research projects illustrate these advances:

- ***Characterization of Emerging Alabama Shale Gas Plays*** - A project carried out by the Alabama Geological Survey determined that the shale formations of Alabama (Chattanooga, Consuaga, and Floyd-Neal shales) contain a total

Enhanced Understanding of the Bakken Shale

Colorado School of Mines carried out an integrated geologic and geophysical study of the Bakken petroleum system in the Williston basin of North Dakota and Montana. This analysis, the first public study of its kind, revealed that dolomite is needed for good reservoir performance in the Middle Bakken interval, both regional and local fractures play a significant role in enhancing permeability and well production, and the organic-rich Bakken shale serves as both a source and reservoir rock. Results from the lithofacies, mineral, and fracture analyses of this study were used to construct a dual porosity Petrel geo-model for the Elm Coulee Field and the insights made available by this research are being used by operators to optimize production from this important oil resource.

An ongoing industry consortium was started when the project received NETL funding, and the consortium has grown to 29 members, almost every company who is exploring and producing Bakken oil. The consortium website—http://geology.mines.edu/Bakken/index.html—includes a list of the companies. Additional details on this project are available in the project summaries, p. 25.

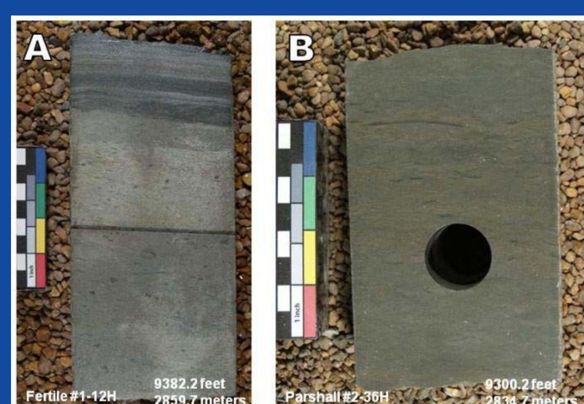


Image caption: Core photos showing Helmithopsis/Sclarituba burrow traces found in facies B.

original-gas-in-place of 826 trillion cubic feet (Tcf), with an estimated technically recoverable resource of between 70 and 139 Tcf. The analysis compiled information about the shales and produced maps, cross sections, and a comprehensive description of their geologic character (e.g., structure, hydrodynamics, geothermics, petrology, geochemistry, and gas content). This report has been used to support leasing activity and could eventually be one factor in the growth of shale gas production in Alabama.

- ***New Ways to Optimize Fracturing and Refracturing of Shale Wells*** - University of Texas carried out a study of the refracturing of vertical and horizontal shale gas wells that had previously been hydraulically fractured. The research revealed that there is an optimum time for refracturing wells in situations where stress reorientation resulting from the original fracturing treatment is important, and that this timing can be estimated for a given set of reservoir conditions so that the subsequent refracture treatment results in maximum productive impact. This knowledge has been used by producers to select candidate wells for refracturing and to evaluate the optimal timing of and potential increase in production associated with, such treatments. Researchers also found that simulation of Barnett shale fracturing sequences indicated that consecutive fracturing (i.e., inducing a series of adjacent fractures) limited reservoir drainage; however, alternate fracturing and zipper-fracs improved stimulation performance in horizontal wells.
- ***Enhanced Understanding of Production from Complexly Fractured Rocks*** - LBNL teamed with Texas A&M U., Stanford U. and several industrial partners, to better understand the relationships among the geophysical, geomechanical and geochemical characteristics of tight gas reservoirs and their impact on the long-term behavior of the fracture system and its effect on production. Producing more than 20 journal articles and conference papers, the research found that the angularity of non-planar and non-orthogonal hydraulic fractures can significantly affect reservoir performance that secondary fractures evolve very shortly after the onset of production, and that diffusion and non-Darcy flow can have considerable effects on the prediction of gas production from shale reservoirs. In addition, the work has provided a basis for the design of a new method for tracking fracture propagation during fracturing.
- ***Enhanced Understanding of Fluid Flow in Tight Rocks*** - Researchers at the Missouri University of Science and Technology and the Colorado School of Mines investigated the flow behavior of natural gas and fracturing fluids (water, surfactant solutions and polymers) in the micro-fractures and nano-sized pores found in tight sand and shale formations. This was conducted using a unique approach that combined an advanced single-molecule imaging system with nano-fluidic chips and pore-scale numerical simulation techniques. The results have provided important insights into possible mechanisms behind the retention of fracturing water in shales. Three different flow patterns were detected when gas displaces water, while two types of flow patterns were found when water displaces gas. The pattern for liquid displacing gas was unique and may cause higher residual saturations of gas.
- ***Development of Nanoparticle-based Drilling and Fracturing Fluids*** - University of Texas developed and tested a temperature-stable, nanoparticle-based drilling fluid that dramatically reduced fluid reactivity with shale formations. This new fluid formulation could be used to reduce the formation damage associated with drilling wells in reservoirs with significant volumes of water-sensitive shales.

These Subsurface Geology and Engineering Research projects include new datasets, new models, prototypes, comprehensive reports, and other insights that provide valuable contributions to industry understanding.

- ***New Insights into Hydraulic Fracturing of the Marcellus Shale*** - Gas Technology Institute, WPX Energy, and a multidisciplinary team of experts from the University of California, Berkeley, Lawrence Livermore National Laboratory, Louisiana State University, and Octave Reservoir Engineering LLC, quantified the impact of various geologic and reservoir parameters on production from the Marcellus Shale. Extensive field data acquisition projects at multi-well pads in southwest and northeast Pennsylvania resulted in over thirty fracturing stages in two horizontal wells being mapped using downhole microseismic imaging followed by production logging. Results to date show more efficient resource development from variable rate stimulation as compared with that from conventionally fractured stages.
- ***A "Next Generation" Hydraulic Fracturing Model*** - University of Texas developed a "new generation" hydraulic fracturing model, based on a *peridynamics* formulation that models multiple, non-planar, competing fractures in heterogeneous shales. Peridynamics enables more accurate three-dimensional modeling of arbitrarily complex fracture geometries and the growth of competing and interacting fractures in naturally fractured media. This new model will lead to recommendations and guidelines regarding cluster spacing, stage spacing, stage sequencing, and fracture design in long horizontal wells for a given set of reservoir conditions.
- ***A Novel Alternative for Routine Seismic Monitoring of Reservoir Behavior*** - Lumedyne Technologies, Inc. has

made a breakthrough that could lead to an alternative to the decades-old geophone used for seismic data gathering: a micro-electro-mechanical (MEMS) accelerometer with improved low frequency response, lower power consumption, lower unit cost, and longer product life. Such sensors could provide higher resolution spatial and temporal imaging, enabling "permanent monitoring" of critical reservoir processes through time-lapse seismic imaging at resolutions of less than a few meters on a widespread, routine basis.
- ***Enhanced Understanding of the Bakken Shale*** - Colorado School of Mines carried out an integrated geologic and geophysical study of the Bakken petroleum system in the Williston basin of North Dakota and Montana. This analysis, the first public study of its kind, revealed that dolomite is needed for good reservoir performance in the Middle Bakken interval, both regional and local fractures play a significant role in enhancing permeability and well production, and the organic-rich Bakken shale serves as both a source and reservoir rock. Results from the lithofacies, mineral, and fracture analyses of this study were used to construct a dual porosity Petrel geo-model for the Elm Coulee Field and the insights made available by this research are being used by operators to optimize production from this important oil resource.
- ***New Understanding of the Risks Posed by Hydraulic Fracturing to Water Supplies*** - DOE monitored the hydraulic fracturing of six horizontal Marcellus Shale gas wells in Greene County, PA using microseismics, chemical and isotopic analysis of produced gas and water, tracer analysis, and pressure measurements. The results illustrated that hydraulic fractures did not extend upwards to shallower gas producing zones and that no detectable migration of gas or aqueous fluids to those zones occurred during or within 8 months after hydraulic fracturing.

Lessons Learned

As with any type of research, subsurface geology and engineering research sometimes yields unexpected findings and uncovers challenges that need to be addressed through further research. The following high-level "lessons learned" have been identified in final reports of completed projects, mostly confirming what is known regarding the complex nature of these unconventional resources.
- **Shale gas reservoirs are complex.** In a number of completed projects, researchers have noted this challenge in their final reports. The challenge for the development of future predictive tools will be improving characterizations of shale, understanding all the variables involved, and adopting new scientific tools and methods that improve measurement and diagnostic capabilities.
- **Not all reservoirs are alike.** It is difficult to create a "one-size-fits-all" model that applies to all reservoirs. Models need to integrate variables specific to the reservoirs in

New Insights into Hydraulic Fracturing of the Marcellus Shale

Gas Technology Institute, WPX Energy, and a multidisciplinary team of experts from the University of California, Berkeley, Lawrence Livermore National Laboratory, Louisiana State University, and Octave Reservoir Engineering LLC, quantified the impact of various geologic and reservoir parameters on production from the Marcellus Shale. Extensive field data acquisition projects at multi-well pads in southwest and northeast Pennsylvania resulted in over thirty fracturing stages in two horizontal wells being mapped using downhole microseismic imaging followed by production logging. Results to date show substantially higher production from variable rate stimulation as compared with that from conventionally fractured stages. Additional details about this project are available in the project summaries on p. 47.

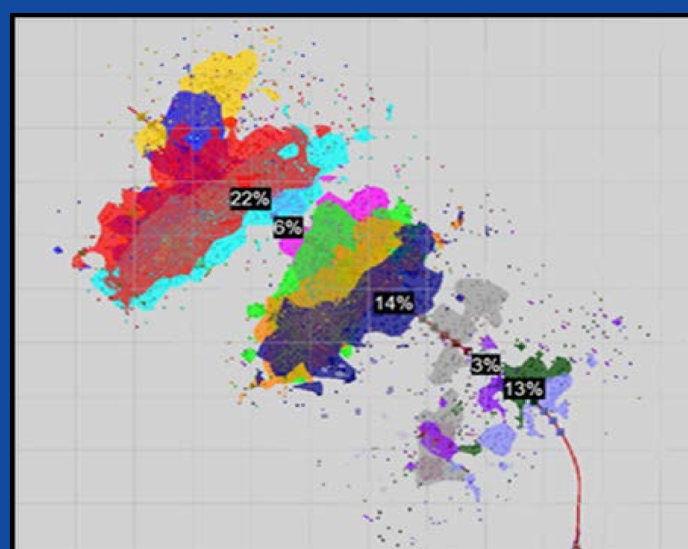


Image caption: **Hydraulic fracture diagnostics help lessen environmental impacts through more efficient design and execution to improve recovery efficiency.**

question and the conditions under which they are being produced.

- **More than one solution may be needed** to resolve some drilling, well completion, and production challenges. In many cases, the hope is that a single remedy will resolve an issue. Sometimes, because many variables are at play, a suite of solutions may need to be exploited to yield the desired result.
- **Collaborative research yields results** and there is no good substitute for bringing together teams of experts from industry, academia and research organizations to tackle specific problems. Such joint efforts are essential when there is a need to go to the field to gather data or test new approaches generated in the laboratory.

What are the benefits of subsurface geology and engineering research?

Subsurface geology and engineering researchers are improving the predictive tools that are being used for drilling, well completion, and production operations. They are also developing cost-effective, reliable, and easy-to-use tools/methods that can be readily deployed to the field. The findings and results of subsurface geology and engineering research have a real impact. Based on findings from these projects, operators in the field are already modifying their procedures to improve well performance, ensure production success, and reduce environmental impacts. Examples include using alternate stage fracturing and zipper fracs as well as using results from the Bakken characterization study.

It can be difficult to predict how a specific federal research portfolio carried out over the last decade will eventually be translated into quantifiable benefits to the U.S. consumer. It is only within the last five or ten years that experts have gone on record connecting the work done by DOE in the Western Tight Gas Sands and Eastern Gas Shales research programs of the late 1970s and 1980s with the surge in unconventional gas production post-2000. However, based on past experience, over the long term the benefits from the accomplishments outlined in this document are expected to include:

- **Increased recovery per well and increased overall recovery of the natural gas and oil resource** located in unconventional reservoirs,
- **Reduced environmental impacts** as a result of fewer well locations, reduced water requirements, enhanced understanding of air emissions, and improved air, water, and well monitoring capabilities,
- Increased supply of natural gas and the concurrent **economic benefits and lower energy prices** associated with such,
- Increased use of natural gas associated with increased supply, and the **concurrent economic and environmental benefits** associated with such.

Image caption: **Three Marcellus shale wells ready for sequential fracturing.**

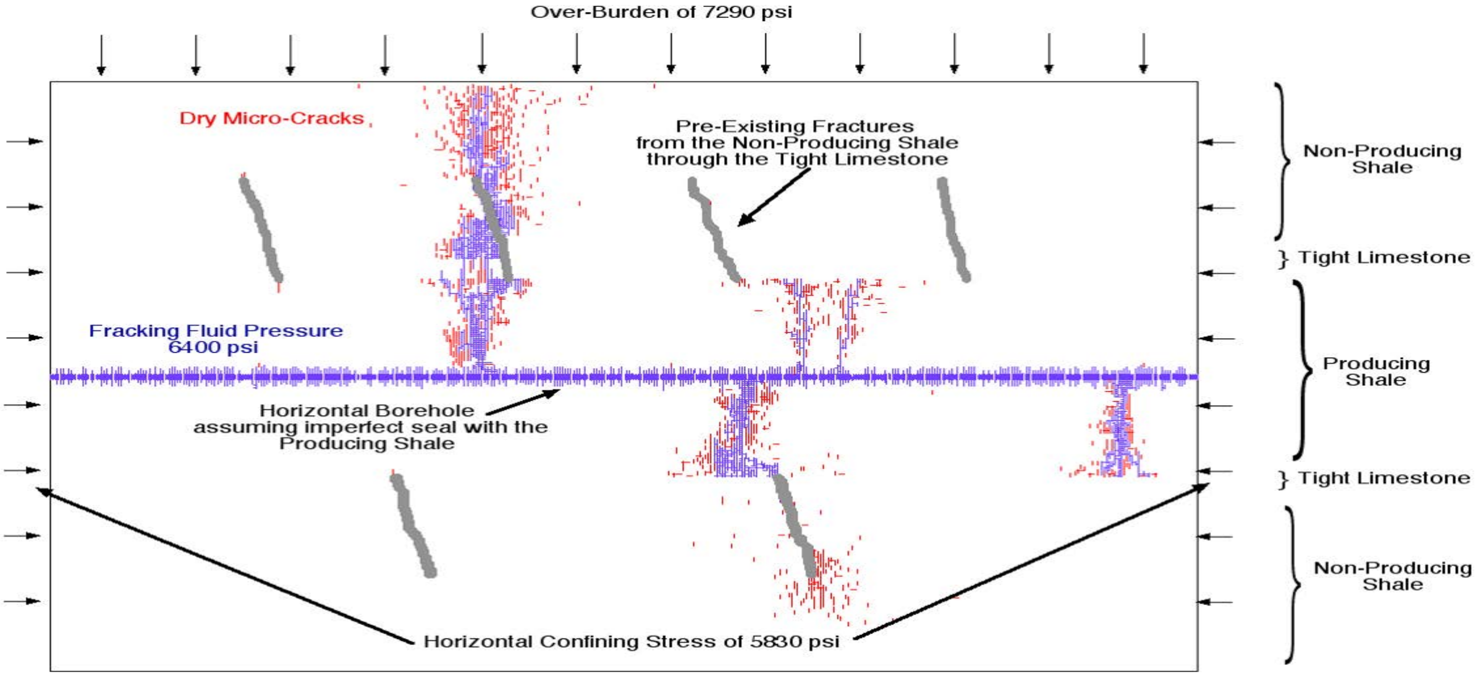


Image caption: **Geophysical and geomechanical factors that affect subsurface fluid and gas migration.**

Matrix of Subsurface Geology and Engineering Projects

Bin sub-area / project	Lead performer	Report page no.
GEOLOGICAL CHARACTERIZATION		
07122-15: Reservoir Connectivity and Stimulated Gas Flow in Tight Sands; Stratigraphic Controls on Higher-Than-Average Permeability Zones in Tight-Gas Sands, Piceance Basin	Colorado School of Mines	16
07122-16: New Albany Shale Gas	Gas Technology Institute	17
07122-17: Geological Foundation for Production of Natural Gas from Diverse Shale Formations	Geological Survey of Alabama	18
07122-45: Paleozoic Shale-Gas Resources of the Colorado Plateau and Eastern Great Basin, Utah: Multiple Frontier Exploration Opportunities	Utah Geological Survey	19
09122-04: Marcellus Gas Shale Project	Gas Technology Institute	20
09122-07: Cretaceous Mancos Shale Uinta Basin, Utah: Resource Potential and Best Practices for an Emerging Shale Gas Play	Utah Geological Survey	21
10122-47: Predicting Higher-than-Average Permeability Zones In Tight-Gas Sands, Piceance Basin: An Integrated Structural and Stratigraphic Analysis	Colorado School of Mines	22
FE0010667: Liquid Rich Shale Potential of Utah's Uinta and Paradox Basins: Reservoir Characterization and Development Optimization	Utah Geological Survey	23
FE0005643: Geomechanical Study of Bakken Formation for Improved Oil Recovery	University of North Dakota	24
NT0005672: The Bakken—An Unconventional Petroleum Reservoir System	Colorado School of Mines	25
NUMERICAL RESERVOIR SIMULATION		
07122-23: A Self-Teaching Expert System for the Analysis, Design and Prediction of Gas Production from Shales	Lawrence Berkeley National Lab	26

Reservoir Connectivity and Stimulated Gas Flow in Tight Sands; Stratigraphic Controls on Higher-than-Average Permeability Zones in Tight-Gas Sands, Piceance Basin—Colorado School of Mines; 9/2008-5/2012

Objective: The project objective was to improve the predictive capabilities in the exploration, completion, and production of reservoirs in the Piceance Basin, Colorado.

Research Conducted: This comprehensive research project comprised multiple tasks in geology, geophysics, petroleum engineering, and rock mechanics designed to explore relationships between the architecture of tight gas reservoirs and their fluid flow characteristics. Specifically, the team provided data and analysis of the structural and stratigraphic controls for static reservoir models for the Mamm Creek Field in the Piceance Basin, and explored the larger scales of architecture (at basin rather than the reservoir scale) with the largest scale being that of the formation of the entire paleogeography of the region at the time of deposition of gas-bearing strata. The team used these studies to run dynamic models to properly understand flow connectivity in a portion of the Mamm Creek Field and discrete element models to move reservoir connectivity analysis beyond the empirical and towards a predictive science based on the mechanics of failure in rocks subject to stress. Included in this comprehensive study of tight gas sandstone reservoirs in the Piceance Basin were four geophysical studies built around an evaluation of vertical seismic profiling for improved reservoir imaging, improved accuracy in locating microseismic events , understanding the fundamental properties of the self-potential field in basin-center gas accumulations, and the advancement of seismic shear wave anisotropy analysis to characterize fracture orientation and, possibly, other anisotropic reservoir properties.

Accomplishments: Accomplishments include clear documentation that diagenetic cements play a significant role as flow barriers within sandstone bodies and comprehensive stratigraphic studies documenting the basin-specific distribution of reservoirs, seals, and potential migration pathways, which provide profound new insights into gas charge distribution, the role of stratigraphic as well as structural traps, and the timing of gas generation from major source rocks. Research also demonstrated how an integrated approach based on reservoir characterization studies and modeling led to more realistic 3-D geologic and dynamic models that are consistent with static data and historical performance. Additional accomplishments include determining that 3-D vertical seismic profiling using shear waves offers significantly improved data compared to recording by means of surface geophones; a new approach to determine the precise location of microseismic events based on reconstructing the entire wave field as seen from sets of receivers sensing waves arriving from different directions; and several new advances in processing methods to more effectively use shear waves in detecting reservoir anisotropy.

Ongoing Activity and Future Plans: This project has been completed, and no further activities are planned.

Lessons Learned: One finding generated by the project studies is that stratigraphic trapping may play a role in the gas distribution. This finding resulted from reviews of the comprehensive datasets provided by industry.

Benefits: New models and methods were developed that may help predict the best locations to drill new and more productive wells. They may also provide additional insight into ways to stimulate the production of existing gas wells. Overall gas recovery from the Mamm Creek field could increase by 25 percent based on this comprehensive understanding of the field geology and new engineering approaches. Increases in gas production could result in more tax revenue, higher royalties, and greater regional economic benefits.

Key Contacts: Dag Nummedal, Colorado School of Mines, 303-384-2506, nummedal@mines.edu

Jennifer Aschoff, Colorado School of Mines, jaschoff@mines.edu

Project Number: 07122-15

The final report for this project is available at: https://www.dropbox.com/sh/tiezr0du53b66l5/ctyV2HlZC6.

New Albany Shale Gas—Gas Technology Institute; 7/2008-11/2010

Objective: New Albany shale underlay the states of Illinois, Indiana, and Kentucky. This shale is difficult to evaluate because the main component of the carbon is oily, which, with water and absorbed gas, restricts the space available for free gas in the shale. It also has low permeability, which makes it more difficult for gas to move through the shale, slowing the release of gas and limiting the development of this resource. New Albany Shale can hold vast amounts of natural gas, but more information is needed in order to determine its gas generating potential. The goal of this project was to identify and explore the development of techniques and methods for increasing the success ratio and productivity of New Albany Shale wells to a level where otherwise non-commercial wells may become commercial producers.

Research Conducted: Researchers sampled wells in western Kentucky and southern Indiana to understand the composition of New Albany shale and gas. Experimentation and modeling were conducted to identify impediments to well development and develop extraction techniques. Production data were obtained from more than 250 wells, 360 feet of core samples were analyzed, and 45 water samples were studied.

Accomplishments: Researchers found that natural fractures are common in New Albany shale, but that they vary in character, indicating formation by different mechanisms. Calcite was the most common fracture sealant, but some fractures were sealed by both calcite and quartz. In the samples, researchers found live, but nearly dormant, methane-producing bacteria. Internal conditions within the shale, such as water availability and organic matter composition, limit bacterial activity but may have a high potential for methane production. New Albany shale contains almost vertical natural fractures that run east-west. Well performance could be increased by drilling a horizontal well. Sensitivity analyses indicated that increasing fracture length or density would increase productivity. Additional modeling suggested that the number of fractures be increased and that the fracture stages, the different levels or locations of fracture within the well, be spaced closer (at 50 feet) in order to achieve a higher gas recovery rate over an estimated well lifetime of 30 years.

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

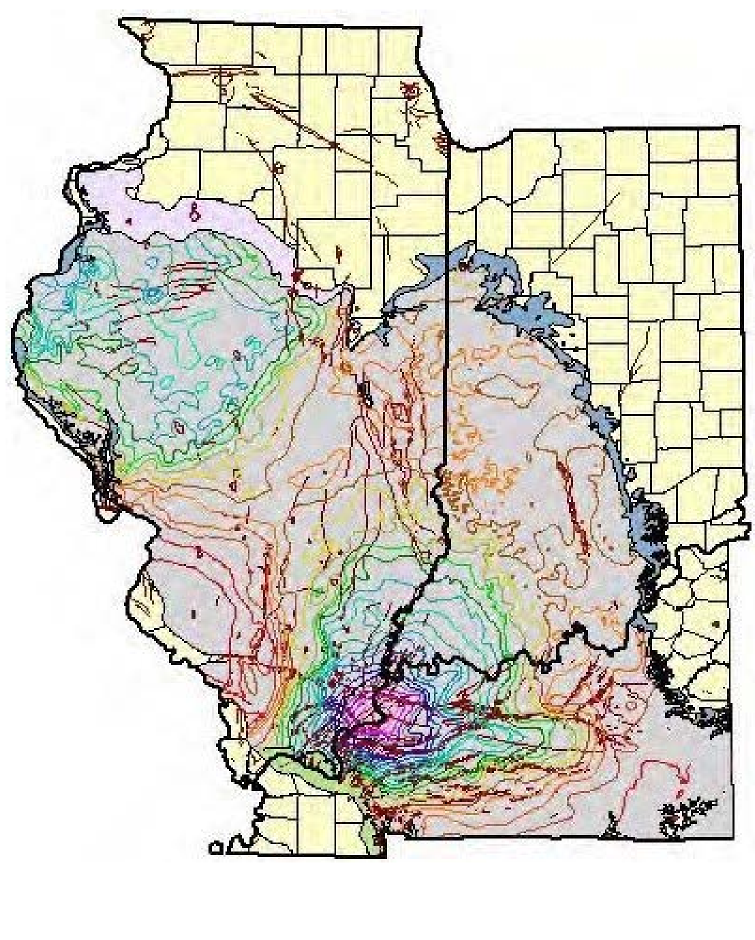
Lessons Learned: The New Albany is a shallow, low-pressure shale formation with very low permeability. Current technology will not achieve commercial production from this formation. Significant gas in place, shallow depth, and proximity to markets, however, all add to the potential. A new approach to well drilling and completion that significantly reduces cost will be needed to exploit this resource.

Benefits: With the data and modeling information generated by this project, potential productivity for gas wells in New Albany Shale areas can be determined with more certainty, which saves time and money and can reduce negative environmental impacts.

Key Contact: Iraj Salehi, Gas Technology Institute, 847-768-0902, iraj.salehi@gastechnology.org

Project Number: 07122-16

The final report for this project is available at: http://www.rpsea.org/files/1931/.



Geological Foundation for Production of Natural Gas from Diverse Shale Formations—Geological Survey of Alabama; 7/2008-7/2011

Objective: The first commercial gas production from shale in Alabama was in 2005 with the discovery of gas in the Conasauga formation. These shales bear deformations in the form of folds, faults, and fractures. They have a wide range of reservoir properties; however, not much is known about the underground structure of this area, which adds to both the risk and cost of developing these gas resources. The primary objective of this research was to develop a conceptual and procedural foundation for the exploration and development of gas shale resources in the emerging gas shales plays of the Black Warrior Basin and Appalachian thrust belt of Alabama.

Research Conducted: This study was designed to reduce risks associated with exploration and development and to provide an accurate assessment of resources and reserves in these plays where industry is facing a broad range of technical challenges related to complex reservoir geology in shale formations of Cambrian through Mississippian age.

Researchers used outcrops, cores, well logs, and seismic profiles to determine shale characteristics. Well location data from 1,089 wells comprised a database used to produce maps of shale structure and thickness. Well logs and file reports provided information on gas pressure and bottom-hole temperatures. Gas samples were taken, observations were made from slabbed cores, and samples were cut to determine rock chemistry and physics. Gas reservoirs were gridded and mapped using the database. Stratigraphy, sedimentation, structure, hydrodynamics, geothermics, petrology, geochemistry, gas storage, and permeability were explored and examined in this project.

Accomplishments: This project expanded the exploration of Neal shale, Conasauga shale, and Devonian gas shales in the Black Warrior basin and the Appalachian Thrust Belt of Alabama by characterizing their features and determining their natural gas production potential. The shales included in this project differed in their composition. Conasauga shale contained an abundance of carbonate. Devonian shale was clay shale or siltstone. Neal shale is richer in clay shale. Core analyses of the porosity and permeability of these shales indicated that they are capable of holding large volumes of natural gas. The Devonian (Chattanooga) shales were much more permeable than the other shales with the Neal shales having the lowest permeability.

Research indicated that the Chattanooga shale in the Black Warrior basin has limited development potential in most of the areas assessed with the exception of the northern area, which includes the reservoirs in Blount and Cullman counties, and the southern areas of the basin. Wells in the northern area may behave similarly to coalbed methane wells. In the Neal shale the greatest potential is in the southern part of the study area; shale in the northern area is likely too immature to produce gas. Data indicated that success might be greater if exploration focuses on the interiors of large fault blocks. The general lack of gas produced by existing wells in Neal reservoirs may indicate undersaturation; however, deep Neal shale has not been explored, which may hold the greatest area of saturation. Conasauga shale has high potential. The challenge will be technological in determining how to produce gas from the folds and faults of deformed shale. Gas in these shale formations is estimated to be about 826 trillion cubic feet (Tcf). Areas with significant potential are between 70 and 139 Tcf, which demonstrates that these shales contain enough natural gas to have a major impact on domestic gas reserves.

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

Lessons Learned: The Conasauga shale is a resource for the future, and it and other resources of its type will need to be developed if the U.S. is to increase its shale production to approximately 50 percent of total gas production. Developing the Conasauga economically will require focused research applied to the very difficult drilling conditions to overcome drilling challenges.

Benefits: This project identified an additional 150 Tcf of technically recoverable gas, indicating that the Alabama shale formations represent significant targets for shale gas exploration. Meeting the challenges posed by these formations can add greatly to domestic natural gas reserves as well as prove new exploration and development technologies that can be transferred to new regions.

Key Contact: Geological Survey of Alabama, (205) 349-2852

Project Number: 07122-17

The final report for this project is available at: http://www.rpsea.org/media/files/project/4cdb44a4/07122-17-FR-Geological_Foundation_Production_Natural_Gas_Diverse_Shale_Formations-07-30-11_P.pdf.

Paleozoic Shale-Gas Resources of the Colorado Plateau and Eastern Great Basin, Utah: Multiple Frontier Exploration Opportunities—Utah Geological Survey; 8/2008-5/2012

Objective: Paleozoic shales in Utah have potential to produce significant recoverable gas reserves due to their thickness, depth, organic material, and fractures. More exploration of the Manning Canyon (Mississippian/Pennsylvanian Doughnut formation) and the Chimney Rock, Gothic, and Hovenweep (Pennsylvanian Paradox formation) gas shales is needed. The overall goals of this study are to (1) identify and map the major trends for target Paleozoic shale reservoirs and identify areas having the greatest gas potential; (2) characterize the geologic, geochemical, and petrophysical rock properties of target reservoirs; (3) reduce exploration costs and drilling risk, especially in environmentally sensitive areas; and (4) recommend the best practices to complete and stimulate these frontier Paleozoic gas shales to reduce development costs and maximize gas recovery.

Research Conducted: Researchers compiled data from wells, logs, cores, cuttings, outcrops, and formation tests, analyzing these data to characterize attributes such as density, porosity, permeability, and saturation. Thin section, scanning electron microscope, and X-ray diffraction analyses were also conducted on samples. Lithotypes identified in the Manning Canyon formation included packstone, wackestone, mudstone, siltstone, fine-grained sandstone, black shale, and coat. The gas play area was in a broad structural depression beside the Uncompaghre uplift. The pore systems in this shale are poorly interconnected, which contributes to a very low permeability and limits its gas-producing viability; however, its brittle silty shale beds could be fractured for access to the gas reservoirs. Cores from the Paradox formation included shale beds that were mainly mudstone containing silt, pyrite, and fossils. Dolomite beds and some shale have many subvertical fractures filled with calcite. Gas production will likely come from the carbonates and natural fractures, as well as the shale. These shales also exhibit low porosities. Gothic shale within the Paradox formation holds the greater gas potential of the shale studied in the project.

Accomplishments: Knowledge gained through data analysis and modeling enabled researchers to identify "sweet spots" that have the greatest gas potential. Recommendations for well completion in the shales are to drill horizontal wellbores instead of vertical wellbores; install swell packers with mechanical sliding sleeves, which isolate and treat long horizontal sections; treat slick water stimulation fluid with as few additives (particularly gelling agents) as possible and with very small proppants; start out on the larger end of the scale in terms of fluid volumes and then increase or decrease fluid volumes during development; and conduct post stimulation follow-up with radioactive tracers, microseismic mapping, and production logs.

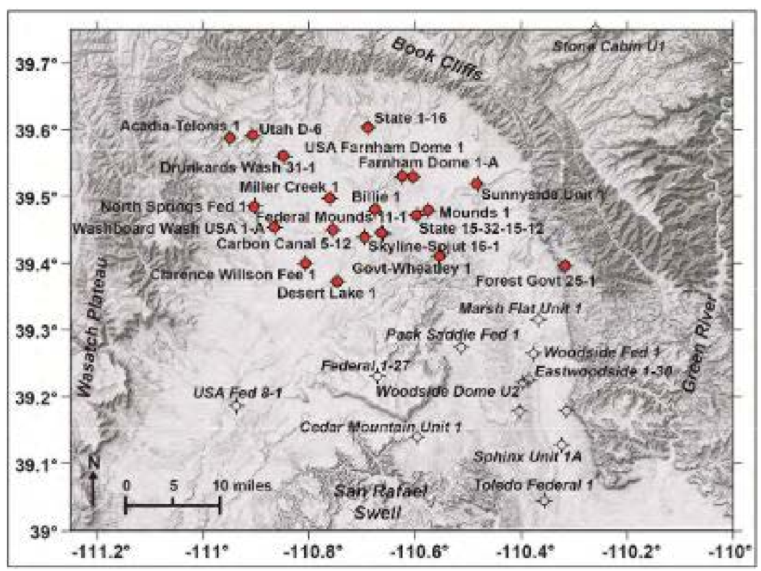
Ongoing Activity and Future Plans: This project is complete, and no further activities are planned

Lessons Learned: Although the Utah Division of Oil, Gas, and Mining database identified 712 wells in this area, only two of these wells produced gas from the shales studied in this project. Best practices do not have much value if based on such a small sample size. Ultimately, the project identified current practices for completing wells in these shales.

Key Contact: Thomas Chidsey, Utah Geological Survey, (801) 537-3300, tomchidsey@utah.gov

Project Number: 07122-45

The final report for this project is available at: http://www.rpsea.org/files/3628/.



Locations of exploration wells fully penetrating the Doughnut Formation (red fill) in the northern San Rafael Swell area of east-central Utah.

Marcellus Gas Shale Project—Gas Technology Institute; 11/2010-6/2013

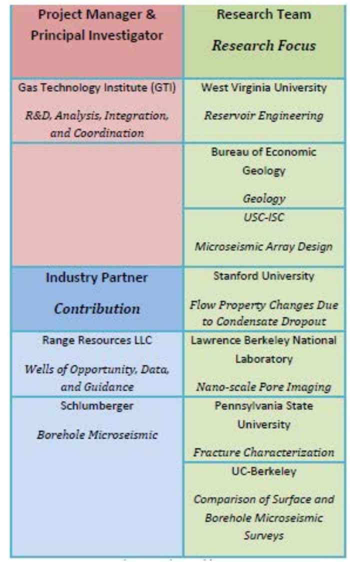
Objective: Marcellus shale presents unique challenges that can best be addressed through a close working relationship between researchers and industry. This completed project was a collaborative effort by five universities, one national laboratory, and one industry consortium. Together, they compiled and analyzed data from Marcellus shale gas production. The resulting model will help predict distribution and characteristics in Marcellus shale systems.

Research Conducted: This project entailed both gathering historical data and gathering fracture stimulation field data from a multiple-well pad owned and operated by Range Resources Appalachia LLC in Pennsylvania. The data was analyzed by the researchers for different factors including flow property changes and nano-scale porosity, and the final compiled results and new model from the project represent the combined expertise of the project participants.

Accomplishments: Each of the members of the research team approached the historical data and field data using techniques and models from their own discipline. This combined analysis gave a richer picture of the Marcellus shale system. This project demonstrated that combined analysis of hydraulic fracturing and microseismic parameters with production logging can lead to identification of naturally-fractured zones during hydraulic fracturing. The integration of many diverse fields (e.g., geology, engineering, geophysics) and technologies (e.g., nano-scale imaging) related to shale gas production was a significant accomplishment on this project.

Ongoing Activity and Future Plans: This project is complete, and no future activities are planned.

Lessons Learned: The researchers confirmed that they could effectively identify natural fractures during hydraulic fracturing when they coupled hydraulic fracturing and microseismic parameters with production logging data. The project also demonstrated that the spatial distribution of natural fractures can be predicted using geomechanical modeling. Also, minimizing fracturing fluid use during stimulation can lead to higher efficiency fracturing. Future Marcellus shale well development needs to involve more spacing between wells because of the scope of the hydraulic fracture treatments; the researchers observed communication between wells during this project, indicating that the wells were too close together.



This project was a collaborative effort between universities, a national lab, and industry.

Benefits: One outcome of this project was a new simple bimodal production decline analysis method; this tool will be useful for future single well production analysis. Results of this project are being disseminated out as each project participant from academic institutions and industry is sharing the results in their own "circle of influence."

Key Contact: Jordan Ciezobka, Senior Engineer, Shale Gas Research, Gas Technology Institute

Project Number: 09122-04

The final report for this project is available at: http://www.rpsea.org/files/3629/.

Cretaceous Mancos Shale Uinta Basin, Utah: Resource Potential and Best Practices for an Emerging Shale Gas Play—Utah Geological Survey; 10/2010-6/2014

Objective: The Mancos is an emerging gas play, with at least four members known to have shale-gas potential: the Prairie Canyon (Mancos B), the Lower Blue Gate Shale, the Juana Lopez, and the Tropic-Tununk Shale. Existing gas production in the Uinta Basin could be augmented with potential reserves in the Mancos; however, target reservoirs remain largely unidentified as the Mancos is geologically distinct from established shale gas plays nearby. Despite the potential for recoverable gas, they represent an economical and developmental risk for industry because geologic characterizations and engineering best practices specific to the Mancos do not yet exist. The objectives of this project include quantifying and reducing the economic risk to potential shale-gas developers by identifying and mapping target reservoirs based on geological and geochemical characterizations, and using that information to develop best practices for gas recovery for specific targeted intervals based on their rock properties. Ultimately, this project will also produce a GIS-based geologic characterization of the Mancos Shale, complete with drilling, completion, and stimulation method recommendations.

Research Conducted: Researchers evaluated and compiled existing geologic and engineering data, including 125 well logs from the Uinta Basin and overlying flooding sequences, 3D seismic information, production data, descriptions and petrophysical, geochemical, and rock mechanical analysis of cores and cuttings from public sources and industry partners. Additional geochemical data was from cores, cuttings, and outcrops as needed. For example, natural fracture measurements were collected and compared with borehole imaging logs to determine whether fracture orientations and stress regimes existed. Cores were sampled for tight-rock 3D analysis, the results of which were used to determine the geologic parameters that influence successful shale-gas recovery.

Accomplishments: Researchers established a regionally-significant depositional and stratigraphic framework that can be tied to lithologic, petrophysical, and geomechanical properties. The framework allowed them to evaluate resource plays of the Mancos Shale and similar offshore deposits of the Western Interior Seaway. The 3D surveys indicated that lithologic composition may influence the direction and style of fault formation. Eleven heterogenic Mancos facies were also analyzed and defined, and a comparison of geomechanical properties resulted in a unique method for quantifying fracture potential. After integrating this model with core and log analyses, two specific zones in the Mancos were identified as potential exploration targets. Researchers also created a geographic model and established best-practices for drilling, completion, and production techniques from targeted intervals.

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

Lessons Learned: Core analysis showed unexpectedly-high water saturations—about 10% higher than calculated from logs. Additionally, modeling of reservoirs indicated vertically layered permeability models and homogenous permeability models predicted different production values.

Benefits: The project will help reduce development costs and risk for potential producers, while maximizing gas recovery, by identifying and mapping areas with the greatest potential for shale-gas recovery. The searchable GIS data catalogs the characteristics of those areas' properties. The GIS data and all other materials generated by this research are available to the public, industry professionals, and other researchers through the project website at: http://geology.utah.gov/emp/shalegas/cret_shalegas/index.htm. This project adds valuable data to the general body of knowledge and advances geologic and other research as well as gas recovery efforts. Additionally, it protects an important environmental asset through the recommendation of best practices for completing and stimulating the Mancos gas shale plays.

Key Contact: Robert Ressetar, Utah Geological Survey, 8201-537-3314, robertressetar@utah.gov

Project Number: 09122-07

This project is ongoing; therefore the final report is not yet available. Additional details about this project are available through the RPSEA website at: http://www.rpsea.org/projects/09122-07/.

Predicting Higher-Than-Average Permeability Zones in Tight-Gas Sands, Piceance Basin: An Integrated Structural and Stratigraphic Analysis—Colorado School of Mines; 4/2012-9/2014

Objective: Predicting good gas well production sites requires good regional stratification data. This active project is helping increase stratigraphic knowledge of the Piceance Basin in Colorado. The specific tasks for this project include 1) constructing a grid of stratigraphic cross-sections; (2) identifying, describing, measuring and interpreting depositional facies within the regional stratigraphic context; (3) determining geographic and/or stratigraphic trends in fluvial architecture as they relate to higher-than-average permeability zones; (4) constraining paleocurrent patterns in high-resolutions depositional sequences; (5) measuring outcrop GR responses of key lithofacies to constrain the outcrop-subsurface link; and (6) defining potential mechanical units based on facies.

Research Planned: Some tight sandstone samples have been measured for rock properties (including porosity and permeability). The results will be validated. The researchers will be building and testing the injection apparatus.

Results to Date: The researchers are continuing sedimentologic analysis of the Williams Fork formation and extending the outcrop work to the subsurface. This research has led to revisions to the subregional, detailed sedimentology. The researchers have also finished structural stratigraphic interpretation of the Mamm Creek 3D seismic depth column which yielded detailed structural analysis of seismically-visible faults on a line by line spacing.

Ongoing Activity and Future Plans: This project is scheduled to complete in July 2015. According to the project management plan, the following deliverables will be submitted at the conclusion of the project: (1) database and map showing stratigraphic profile (new and published) and well-log locations; (2) 15-30 drafted and interpreted stratigraphic profiles; (3) facies tables highlighting key internal heterogeneities and mechanical properties; (4) gamma-ray profiles for 8 of the stratigraphic profiles; (5) 4 Regional, stratigraphic cross-sections close to the outcrop belt; and (6) overlay maps: isopach, net sand maps and detailed depositional environment (DDE) maps.

Benefits: This project will integrate structural, stratigraphic and diagenetic data for tight-gas sandstones; this knowledge will help improve exploration and production techniques and lead to fewer wells drilled.

Key Contact: Dr. Jennifer Aschoff, Colorado School of Mines.

Project Number: 10122-47

This project is ongoing; therefore, the final report is not yet available. Additional project details are available through the RPSEA website at: http://www.rpsea.org/projects/10122-47/.

Liquid Rich Shale Potential of Utah's Uinta and Paradox Basins: Reservoir Characterization and Development Optimization—Utah Geological Survey; 10/2012-9/2015

Objective: The overall goal of the project is to provide reservoir-specific geological and engineering analyses of the emerging Green River Formation (GRF) tight oil plays in the Uinta Basin, and the established, yet understudied Cane Creek shale (and possibly other shale units) of the Paradox Formation in the Paradox Basin. Specific objectives are to (1) characterize geologic, geochemical, and geomechanical rock properties of target zones in the Uinta and Paradox Basins by compiling data and analyzing available cores, cuttings, and well logs; (2) describe outcrop reservoir analogs of GRF plays and compare them to subsurface data; (3) map major regional trends for targeted intervals and identify "sweet spots" that have the greatest oil potential; (4) reduce exploration costs and drilling risks, especially in environmentally-sensitive areas; (5) improve drilling and fracturing effectiveness by determining optimal well completion design; and (6) reduce field development costs, maximize oil recovery, and increase reserves.

Research Planned: The research team conducted reservoir characterization and analysis (i.e., fracture, geochemical) based on newly-acquired and donated core, well logs, and well cuttings, to improve well placement and establish a relationship between natural fractures and productivity. The team used geophysical and other geomechanical data to analyze in situ stress to improve hydraulic fracture design for development of new fields or expansion of established fields.

Results-to-Date: The team located and described all available cores from the two primary target intervals in the Uinta and Paradox Basins. Project team members located and described in detail ten lower GRF cores (mostly from the Uteland Butte Member) and collected all associated data. These data will help project members to develop a regional geologic picture of the Uteland Butte play and determine where data gaps exist. Project team members also described four cores from the Cane Creek shale in the Paradox Formation, collecting high-resolution X-ray fluorescence data and conducting RockEval analyses, X-ray diffraction, and other core analyses.

Ongoing Activity and Future Plans: The team is collaborating with Dr. Hans Machel—geology professor at the University of Alberta and dolomite expert—to explore the origin of the Uteland Butte's productive dolomite intervals and subsequent diagenesis. The team is also collaborating with Dr. Joseph Moore—research professor at the Energy and Geoscience Institute, University of Utah, and fluid inclusion expert—to study fluid inclusions in the Cane Creek shale to help determine timing of fractures and oil generation. The researchers collaborated with research geologists from the U.S. Geological Survey to study the origins of Green River oils and thermal maturity of Green River shales.

The research team initiated a comprehensive geomechanical testing program with TerraTek to help determine reservoir mechanical properties and optimize well completion strategies in both the Uteland Butte and Cane Creek plays. Testing should commence in June 2014 with delivery of preliminary results by fall 2014.

Several new cores from the Cane Creek shale have been donated/borrowed from collaborators and will add greatly to the team's knowledge of the play. Epifluorescence and fluid inclusion analyses will begin in the next few months.

Benefits: Successful completion of this project will provide operators with the information needed to reduce exploration and development costs and drilling risks in the Green River and Paradox Formations in the Uinta and Paradox Basins, respectively, while maximizing oil recovery and increasing reserves.

Key Contact: Michael Vanden Berg, Utah Geological Survey, michaelvandenberg@utah.gov, 801-538-5419

Project Number: FE0010667

This project is ongoing; therefore, the final report is not yet available. Additional details on this project are available through the NETL website at: http://www.netl.doe.gov/research/oil-and-gas/project-summaries/enhanced-oil-recovery/de-fe0010667.

Geomechanical Study of Bakken Formation for Improved Oil Recovery—University of North Dakota; 10/2008-12/2013

Objective: Successful horizontal drilling and economical crude oil extraction from the Bakken Formation in the North Dakota Williston Basin depends on an understanding of the local in-situ stress and geomechanical properties of the formation rocks within it. The limited information available of these properties has resulted in some production areas experiencing a success rate of less than 10 percent (with wells costing three to six million dollars each) due to wellbore instability and unsuccessful fracturing.

The objective of this project is to produce 3D geological models, an in situ stress orientation map, and application guidelines that can be used for horizontal drilling and/or hydraulic fracturing operations in the Bakken Formation. Researchers will determine the in situ stress and geomechanical properties of the Bakken formations to increase the success rate of horizontal drilling and hydraulic fracturing with the goal of improving the ultimate recovery of 200–400 billion bbl. of unconventional crude oil resource from the current 1 percent to a more acceptable level (nationwide average of 30 percent).

Research Conducted: The research team screened wells and collected and analyzed data for representative areas and wells within the study area. The team also integrated field, well, core, and lab test data using innovative experimental techniques and a sampling system developed in-house to create a Bakken Formation maximum horizontal in situ stress orientation map, a web-based Bakken geomechanical property database, and a 3D Bakken geological model to include factors affecting in situ stresses such as structural features and basin stress history.

Accomplishments: The research team accomplishments included developing an innovative plugging system and techniques for cutting Bakken cores in any desired orientation, reaching a 90 percent success rate; creating intensity maps of vertical, maximum horizontal, and minimum horizontal stresses in the Middle Bakken study area; constructing 3D Bakken geological models using data from 2800+ wells; and developing a Bakken Formation maximum horizontal in situ stress orientation map based on existing data from 16 wells. The team also described fractures in 95 cored Bakken wells, measured rock quality designation (RQD) data of all available Bakken cores, developed a 3-D RQD model of the Bakken Formation in the Williston Basin, and created a web-based Bakken geomechanical property database (http://www.petrodata.und.edu/).

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

Benefits: Successful results from this project may directly benefit oil production in the Williston Basin, and the related technologies developed under this project will contribute to the exploration and production of oil and gas from other unconventional resources.

Key Contact: Dr. Kegang Ling, University of North Dakota, kegang.ling@engr.und.edu or 701-777-3194

Project Number: NT0005643

The final report for this project is available at: http://www.netl.doe.gov/File%20Library/Research/Oil-Gas/enhanced%20oil%20recovery/nt0005643-final-report.pdf.

The Bakken - An Unconventional Petroleum Reservoir System—Colorado School of Mines; 10/2008-12/2011

Objective: The objectives of this project were to accurately assess the hydrocarbon potential for the Bakken stratigraphic interval on a sub-regional basis; construct an integrated exploration model for the Bakken; and build a fully integrated three-dimensional reservoir geo-model for the Middle Bakken reservoirs in the Elm Coulee area.

Research Conducted: The team conducted research to develop a fully integrated exploration model that can be tested outside the sub-regional area of the project. This model creates an integrated stratigraphic framework and couples it with research results on rock physics calibrated seismic attribute analysis and acoustic impedance for different levels of organic richness and maturity to predict high potential fairways and traps for the Bakken hydrocarbon system. This model included secondary permeability potential derived from additional sub-regional fracture analysis.

The team worked to validate and revise the predictive model by comparing predicted seismic attributes to known data such as well logs, cores, and permeability and fracture data throughout the Williston Basin, where sufficient seismic data exists. The team also built a stratigraphic/structural geomodel for (but not limited to) the Elm Coulee Field, utilizing all results and data from this study.

Accomplishments: This integrated geologic-geophysical study has accomplished the following objectives over the three year project life: (1) characterization of the lithofacies and mineralogy of the Bakken to identify high performing reservoirs; (2) established that the organic-rich Bakken shales have similar elastic properties and effective stress as the Middle Bakken siltstones and sandstones; (3) established criteria for identifying and mapping natural fractures that are both regional and related to local structures to guide horizontal well drilling to optimize fracture intersection; (4) constructed a dual-porosity Petrel geo-model for a portion of the Elm Coulee Field to provide a starting model for reservoir simulation; and (5) developed criteria to assess the Bakken exploration potential in undrilled areas of the basin.

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

Lessons Learned: The integrated geologic and geophysical study of the Bakken Petroleum System in the Williston basin of North Dakota and Montana indicated that (1) dolomite is needed for good reservoir performance in the Middle Bakken; (2) regional and local fractures play a significant role in enhancing permeability and well production, and it is important to recognize both because local fractures will dominate in on-structure locations; and (3) the organic-rich Bakken shale serves as both a source and reservoir rock.

Benefits: The successful results of this study will aid in the development of an initial alpha version of a predictive exploration model that could be used for future identification of high potential fairways and traps, thus significantly increasing production of the Bakken hydrocarbon system.

Key Contact: Dr. J. Frederick Sarg, Colorado School of Mines

Project Number: NT0005672

The final report for this project is available at: http://www.netl.doe.gov/File%20Library/Research/Oil-Gas/enhanced%20oil%20recovery/nt0005672-final-report.pdf.

A Self-Teaching Expert System for the Analysis, Design, and Prediction of Gas Production from Shales—Lawrence Berkeley National Lab; 12/2008-11/2011

Objective: Unconventional gas resources (shale, coal beds, or tight sands) are hard to characterize and commercially produce. They are often located in geologic systems that are poorly understood, which increases both their risk and cost, discouraging industry investment despite their great potential. Much research has been done on unconventional gas resources, but the information generated has been scattered across many scientific disciplines and industries and is often difficult to access, leading to duplication of effort and inefficient use of time and money. The goal of this project is to create a platform for use by researchers and industry professionals to share data and access analytical and decision-making tools.

Research Conducted: The research team worked to create an easy-to-use, single source, Internet accessible, Self-Teaching Expert System (SeTES) capable of (1) incorporating evolving databases involving any type and amount of relevant data (geological, geophysical, geomechanical, stimulation, petrophysical, reservoir, production, etc.) originating from unconventional gas reservoirs, i.e., tight sands, shale or coalbeds; (2) continuously updating its built-in 'public' database and refine its underlying decision-making metrics and process;(3) making recommendations about well stimulation, well location, orientation, design, and operation; (4) offering predictions of the performance of proposed wells (and quantitative estimates of the corresponding uncertainty); and (5) permitting the analysis of data from installed wells for parameter estimation and continuous expansion of its database. The project team instilled in the system the capacity to learn with experience, improving its solutions over time.

Accomplishments: Data and analytical tools available through SeTES can make recommendations about well stimulation, location, orientation, design, and operation as well as predict the performance of proposed wells. SeTES handles all relevant data types, such as geologic, geophysical, fracturing, and reservoir data, well completion data, and production data. Located on Lawrence Berkeley National Laboratory servers, the SeTES system generated through this project is accessible to the public through the laboratory and can be installed on local computers for private use. The system uses three types of data: public data made available by contributors; semi-public data, which hides identifying data but is usable for computation; and a user's private data, which is protected. Users can upload data through a data manager that combines this data with data already populating the site. Created as a flexible, modular system, SeTES readily accepts added functionality. It can integrate any modeling program in just about any programming language.

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

Lessons Learned: Development of low *k* resources is very complex with many different factors to consider. It is difficult for small companies or individuals to have working knowledge of all of these concepts. This expert system provides a tool, (similar to tax preparation software) that allows individuals to assess complex production issues.

Benefits: Using SeTES may help to reduce the risk and increase the efficiency of unconventional gas resource research and operations, improve productivity, and increase shale gas reserve estimates.

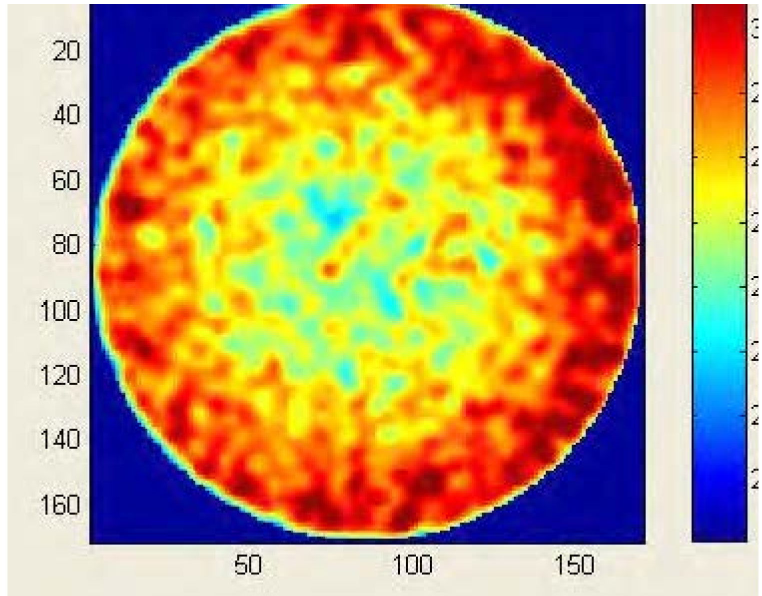
Key Contact: George Moridis, Lawrence Berkeley National Laboratory, 510-486-4746, gjmoridis@lbl.gov

Project Number: 07122-23

The final report for this project is available at: http://www.rpsea.org/media/files/project/e8f981e6/07122-23-FR-SeTES_Self-Teaching_Expert_System_Analysis_Design_Prediction_Gas_Production-11-28-11_P.pdf.

Gas Condensate Productivity in Tight Gas Sands—Stanford; 12/2008-12/2011

Objective: One of the reasons for the decline in production of gas wells is the build-up of condensate underground, which blocks the flow of gas. This occurs when a drop in pressure below the dew point causes the gas to change to liquid. Although some research has been performed on this process, many questions remain unanswered. The objective of this research is to better understand how condensate blocking and reduction in effective permeability affects well productivity with a focus on the influence of composition changes during the flow process.



Research Conducted: Researchers simulated various well conditions in the laboratory using a low-permeability Berea sandstone core sample that was injected with a synthetic gas-condensate mixture to determine the steps needed to limit the effects of the condensation process and aid in the freer flow of gas. Full compositional simulations of binary-component and multicomponent gas-condensate fluids were conducted at field scale to investigate the composition and condensate saturation variations. Different strategies were tested to determine the optimum producing sequences for maximum gas recovery.

Accomplishments: The study found that different producing strategies affect the composition configuration for both flowing and static phases and the amount of the liquid trapped in the reservoir, which in turn influence the productivity and hence the ultimate recovery of gas and liquid from the reservoir. Changing the manner in which the well is brought into flowing condition was found to affect the liquid dropout composition, which can change the degree of productivity loss. Researchers found that increasing the bottomhole flowing pressure of wells producing gas-condensate d\fluids can (depending on the composition) result in a more valuable flow stream (in terms of net present value). One important consequence of the composition variation examined in this work is that reservoir fluid progressively changes from a gas condensate to a volatile oil because the heavier components are left in the formation due to relative permeability effects.

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

Lessons Learned: Fluid blockage near the wellbore for low *k* formations further decreases already flow capacity. This research suggests producing wells at different flowrates than conventionally utilized to control fluid drop out.

Benefits: A good understanding of how the condensate accumulation influences the productivity and the composition configuration in the liquid phase may help optimize the producing strategy for tight gas sands, reduce the impact of condensate banking, and improve the ultimate gas recovery.

Key Contact: Roland N. Horne, Stanford University, 650-723-4744, horne@stanford.edu

Project Number: 07122-29

The final report for this project is available at: http://www.rpsea.org/files/1792/.

Gas Production Forecasting from Tight Gas Reservoirs: Integrating Natural Fracture Networks and Hydraulic Fractures—University of Utah; 9/2008-12/2012

Objective: The Uinta Basin in eastern Utah produces large volumes of gas and may contain as much as 14 TCF of natural gas. Its unconventional tight reservoirs pose a challenge to gas recovery due to its low permeability. Hydraulic fracturing is used to remove the gas. The objective of this project is to increase gas recovery from the tight gas formations in the Uinta Basin, Utah by creating tools that simulate complex three-dimensional hydraulic fractures on existing natural fractures and simulating gas production. These models will help predict fracture generation and propagation and will aid in forecasting production. The Greater Natural Buttes (GNB) gas field was used to support this project. Although, the focus was on the Mesaverde formation, the Dakota and other formations were also studied.

Research Conducted: Outcrop, log and other data were used to create static fracture models, which will evolve into dynamic models by considering well tests. State-of-the-art geomechanical tools were used to obtain hydraulic fracture geometries given the fracture/stress state of the reservoir.

These geometries were represented explicitly in University of Utah discrete-fracture network reservoir simulators to obtain realistic assessments of gas production from tight gas reservoirs. The project team developed a protocol for creating field-wide natural fracture networks, given static and dynamic reservoir information. Tools were developed to determine more realistic hydraulic fracture geometries in vertical and horizontal wells to provide a better understanding of how to design hydraulic fractures to intersect existing natural fractures. Reservoir simulation of these realistic features was conducted to help optimize drainage and minimize costs. 3-DEC was used to simulate hydraulic fracturing. The FRACMAN tool and the Advanced Reactive Transport Simulator (ARTS) developed at the University of Utah were used to characterize the propagation of fractures. The reservoir simulator STARS was used to verify the results.

Accomplishments: Researchers created a software system accessible via the University of Utah that predicts gas production while taking into consideration the interaction of induced fracturing with natural fracturing in gas reservoirs. (Researchers at the University of Utah will provide guidelines for providing a data set or will work with interested parties to create appropriate data sets and the required workflows.) Various case studies were conducted to test the software. Methodologies were developed to characterize fractures, create discrete fracture networks, generate hydraulic fractures, and perform multiphase flow simulations. These methodologies can be used in any system.

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

Lessons Learned: The project team selected a site in the north-central portion of the GNB for a detailed study to support modeling based on initial recommendations by the operator. Due to a decrease in natural gas prices, drilling in this section did not occur as originally anticipated. As a result, the location for modeling was changed to a different section where core and formation imaging logs were available from the productive portion of the Mesaverde Group.

Benefits: This project is expected to result in better tools for understanding hydraulic fracture propagation, which in turn will lead to more efficient stimulation treatments for the Uinta Basin and other tight gas reservoirs. The cumulative benefit would be determined by the total number of fields where the technology is ultimately applied. The national economic benefit from any incremental increase in domestic gas production would be an increase in tax revenue, royalties, and regional economic benefits.

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Project Number: 07122-44

The final report for this project is available at: http://www.rpsea.org/media/files/project/1a7fd674/07122-44-FR-Gas_Production_Forecasting_Tight_Gas_Reservoirs_Natural_Hydraulic_Fractures-08-23-13.pdf.

Coupled Flow-Geomechanical-Geophysical-Geochemical (F3G) Analysis of Tight Gas Production—Lawrence Berkeley National Lab; 4/2010-3/2014

Objective: This three-phase project included 1) studies and simulations examining the relationship between the properties of naturally-occurring and hydraulically-induced fractures and geophysical markers (e.g., signals in seismic surveys and/or microseismic events); 2) a comparison of models against real data from active production wells; and 3) field testing. The scientists used analysis, laboratory studies, and modeling to study fracture properties and see if they could predict future fracture behavior. Understanding the geophysical markers and the evolution of flow properties and fracture characteristics of reservoirs will allow scientists and industry to predict long-term behavior of fracture systems.

Research Conducted: In the laboratory, scientists documented baseline intact rock properties and baseline fracture properties. They then stimulated the rock through fluid injection, application of shear, and proppant injection and measured the impact of stimulation on the material. The stimulation data was used to help create a coupled flow, geomechanical, geophysical, and geochemical model of fracture systems. The scientists looked at whether Stoneley waves (high-amplitude waves created in boreholes) should be used to help determine the rock properties. Ultimately, the scientists confirmed the existence of Krauklis waves (waves that propagate only along fluid-filled fractures) and determined that Krauklis waves were preferable to Stoneley waves for measuring fracture properties. The models and simulations were tested out in the field.

Through this project, scientists confirmed the existence of Krauklis waves (waves that propagate only along fluid-filled fractures).

Accomplishments: The coupled flow, geomechanical, geophysical, and geochemical model produced through this project can be used by the oil and gas industry to improve production system design, system monitoring, and prediction. This project achieved the development and implementation of an integrated fracture model for tight gas systems (shale).

Ongoing Activity and Future Plans: This project is complete, and no future activities are planned.

Lessons Learned: The key finding of the project was the confirmation of the existence of Krauklis waves; as a result of this discovery, researchers were able to design a new method for tracking fracture propagation during fracturing. Krauklis waves are unique because they only propagate along fractures, emit at a characteristic frequency, and can be initiated. In addition to the discovery of Krauklis waves, the researchers learned that microseismic events constitute only a fraction of subsurface activities; that the composition of the produced gas is impacted by medium porosity and permeability and changes over time; and that the standard stimulation method is preferable to the drill slot approach.

Benefits: The researchers made a number of advances that will benefit industry, including developing new simulation capabilities; creating of a new earthquake relocation algorithm; confirming that Krauklis waves exist and can be used to determine fracture properties and characteristics; and developing a new model describing Krauklis wave behavior. The methodology and models were field tested in the Barnett shale. The results of this study are being shared through high-visibility journals with the oil and gas industry and at conferences and events. The coupled flow, geomechnical, geophysical, and geochemical model resulting from this project can be used by industry to predict fracturing behavior in tight gas systems to improve well stimulation and long-term production.

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Project Number: 08122-45

This project was recently completed, and the final report is not yet available. Additional details about this project are available through the RPSEA website at: http://www.rpsea.org/projects/08122-45/.

Gas Well Pressure Drop Prediction under Foam Flow Conditions—University of Tulsa; 12/2010-12/2014

Objective: During production, gas wells can gradually accumulate excess water that hurts productivity. This excess water causes "liquid loading," the point of minimum pressure where gas can no longer be effectively pumped to the surface. To alleviate liquid loading, operators use a variety of tools and methods to restore productivity, including pumping a surfactant (foam) into the tubing. The behavior of foam in gas wells is still not well understood; therefore, most operators use guesswork when applying foam to a well. The researchers on this project are studying vendor data and conducting research at a new experimental facility to increase understanding of foam behavior which could in turn lead to more-effective foam use in the field.

Research Planned: This project includes the following tasks (some of which have already been completed): design and build an experimental facility with two sizes (2" and 4" diameter) of 40-foot pipes for testing foam; study and improve foam generation and characterization; study the pressure drop behavior when foam is injected into the pipes; analyze and process the data from the foam experiments; define a correlation to properly estimate bubble rise velocity in a vertical pipe; and model pressure drops using the available experimental data and analysis.

Results-to-Date: The researchers continue to collect data from pressure drop in vertical pipe experiments, and they have been developing a predictive model based on data that has already been collected and analyzed.

Ongoing Activity and Future Plans: Most of the data collected from other liquid loading studies comes from experiments on 2" diameter pipes. One interesting finding from Dr. Kelkar's studies on liquid loading is that there is significant variation between the results for 2" and 4" diameter pipes. At a January 2014 Foam Flow Meeting, Dr. Kelkar recommended that future liquid loading testing expand to include larger pipes (5" diameter). The researchers on the current effort are scheduled to finalize the predictive model and draft the technical report of findings in the coming months.

Lessons Learned: The researchers have had success predicting liquid loading using the liquid film method and have been testing the liquid film methodology to analyze the data from their facility.

Benefits: The research results will provide better data and analysis on foam behavior that can assist gas well operators in determining the best type of foam to use to restore well productivity. More-effective foam application could lead to less foam being used and quicker restoration of wells to production.

Key Contact: Dr. Mohan Kelkar, Principal Investigator, University of Tulsa

Project Number: 09122-01

This project is ongoing, therefore the final report is not yet available. Additional project details are available through the RPSEA website at: http://www.rpsea.org/projects/09122-01/.

Simulation of Shale Gas Reservoirs Incorporating Appropriate Pore Geometry and the Correct Physics of Capillarity and Fluid Transport—University of Oklahoma; 11/2010-5/2014

Objective: Valid reservoir simulation is a key for characterizing, developing, and managing a productive shale gas reservoir, as traditional core measurements are difficult to attain in shale rock; however, imaging studies have indicated that the pore geometry in shale gas reservoirs is complex, consisting of hydrophobic, gas-wetting pores in the organic materials, and pores of indeterminate wettability in non-organic parts of the matrix. This matrix is overlain with natural fractures that are presumed to be water-wet, and conversely, fractures produced by stimulation that may have fractional wettability. Methane is stored in the organic portion of the matrix as both adsorbed and absorbed gas, and as pressure changes during gas release, permeability and porosity may increase. Although valid reservoir simulations are necessary for accurately planning, modeling, and predicting the results of production operations, there is no clear understanding of how these pore systems are connected.

Shale gas reservoir models require high complexity and modified physics, and a proper simulator must provide for the appropriate pore geometry complexity. This project will update and modify current commercial shale gas reservoir simulators such that they incorporate physical approximations and pore geometries. The new simulators will allow exploration and production professionals to more accurately model gas and water production based on valid physical assumptions.

Research Conducted: Researchers evaluated the approaches in current literature and identified areas in which those approaches could be improved. They then developed the algorithms necessary to simulate the correct physical principles and pore geometries. To calibrate and validate the algorithms, a prototype 1-D test bed simulator was developed that incorporates the effects of pore proximity on fluid properties and transport-related parameters. The algorithms were tested on laboratory date and field-scale data. The new algorithms were then implemented as modules and tested in selected commercial simulators. Researchers then analyzed the potential for "upscaling" heterogenic nanostructures observed in shale formations.

Accomplishments: This project led to the development of a more robust approach for quantifying crushed shale sample permeability. It also allowed researchers to gain a better understanding of the prolific production of nanoporous shales, explained by quantitatively discerning the relationship between pore proximity and the apparent permeability of porous media for a single capillary tube and a bundle of capillary tubes. Furthermore, they have determined a method for upscaling the microstructural features observed in scanning electron microscope images. This method requires an approach similar to object-based modeling, where organic volume percentages are preserved across several modeling length scales. The project also led to a greater understanding of the influence the maturity of the shale's organics has on fluid distribution and wettability; results indicate that intermediate or low maturity of the organic components may lead to trapping of water.

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

Lessons Learned: This study illuminated the need for ongoing updates to modeling solutions as advances are made in the core body of knowledge. Results also illustrated the substantial proximity effect on phase behavior and modeling. When a large percentage of pore volume is contained in the smallest of pores, significant differences are seen in well productive life calculations, reserves per well estimates, and well productivity. Additionally, in the case of gas-water flows, the effects of capillary non-equilibrium can be substantial. Several molecular dynamics simulation studies also demonstrate that organic pores in shales can potentially be mixed-wet depending on the maturity of the shales.

Benefits: In some shale gas reservoirs (the Barnett, for example), wells that have had extensive hydraulic fracturing usually produce a fraction of the stimulation fluid. This typically leads to water blocks that may negatively impact productivity following refracture treatments. The appropriate model physics built into a reservoir simulator will enable modeling of the stimulation fluid's deposition and may allow for better planning to mitigate these effects. Additionally, through technology transfer routes including presentations at scientific meetings, the modifications to commercial shale gas reservoir simulators have been shared with industry and will contribute to more accurate simulations.

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Project Number: 09122-11

The final report for this project is available at: http://www.rpsea.org/media/files/project/4c4746dc/09122-11-FR-Simulation_Shale_Gas_Reservoirs_Incorporating_Pore_Geometry_Physics_Capillarity_Fluid_Transport-11-10-14_P.pdf.

Next Generation Hydraulic Fracturing Model for Horizontal Wells—University of Texas; 10/2012-9/2015

Objective: The goal of this project is to develop a "new generation" hydraulic fracturing model that, for the first time, will provide an operator with the ability to model the simultaneous propagation of non-planar hydraulic fractures from multiple perforation clusters and create a realistic picture of the stimulated rock volume (SRV) around horizontal wells. The model will be used to simulate the performance of different fracturing fluids and fracture designs to maximize the effectiveness of the SRV to increase well productivity, improve estimated ultimate recovery determinations, and reduce overall horizontal well costs.

Research Conducted: The research team is currently developing the hydraulic fracturing model based on a peridynamics formulation (a recently developed continuum mechanics theory that allows for autonomous fracture propagation). Peridynamics allows three-dimensional modeling of arbitrarily complex fracture geometries and the growth of competing and interacting fractures in naturally fractured media.

Accomplishments: The research team has completed development of a peridynamics formulation of the poroelastic response of a porous medium that for the first time couples fluid flow with elastic deformation in three dimensions in the peridynamics framework. Fracture growth can now be modeled within this new framework. The poroelastic peridynamics model has been validated for with a two-dimensional consolidation problem and for two-dimensional bi-wing planar fracture propagation. In addition, the team has applied the new model to simulate the growth of multiple, non-planar fractures as they propagate through a naturally fractured, heterogeneous formation. Model predictions for the interaction of propagating fractures with natural fractures were shown to agree well with experiments.

Ongoing Activity and Future Plans: The team is now in the final phase of the project where additional features are being added to the model and it is being tested for different applications such as the growth of interacting fractures in a horizontal well and fracture propagation in heterogeneous porous media.

Lessons Learned: We have shown that it is possible to use a non-local model such as peridynamics to capture the essential features of macroscopic geomechanical problems without resorting to finite element or finite volume methods.

Benefits: The ability to realistically model hydraulic fracture propagation will provide a starting point for a better understanding of how fracture design affects the stimulated rock volume and well performance. It is anticipated that the new hydraulic fracturing model will lead to recommendations and guidelines regarding cluster spacing, stage spacing, stage sequencing, and fracture design in long horizontal wells for a given set of reservoir conditions. These recommendations should result in significant performance improvements and cost savings, enabling more wells to be drilled and completed for the same annual budget. Increased reservoir drainage due to improved fracturing will result in more economic and longer producing wells, potentially resulting in a 5 to 10 percent increase in the recovery of oil and gas from these unconventional plays and a reduction in well costs of up to 25 percent. The models will be particularly useful for oil-bearing shales that are more likely to have natural fractures and more complex fracture patterns.

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Project Number: FE0010808

This project is ongoing; therefore, the final report is not yet available. Additional project details can be found on the NETL website at: http://www.netl.doe.gov/research/oil-and-gas/project-summaries/natural-gas-resources/de-fe0010808-uta.

Application of Natural Gas Composition to Modeling Communication within and Filling of Large Tight-Gas-Sand Reservoirs, Rocky Mountains—Colorado School of Mines; 8/2008-1/2011

Objective: Major gas fields in tight sand reservoirs in the Rocky Mountains have proven to be a valuable resource over the past 15 years. Unlike shale, which contains pockets of trapped gas, the gas in tight sands is dispersed. Little is known about how gas fills and moves through these underground areas. In addition, not much information about gas composition is publically available. This lack of information hampers the ability to predict where to drill new wells. Better information could be used to develop new methods to increase the productivity of existing wells. The objective of this project is to better understand how gas spreads into and fills tight sands.

Research Conducted: Conventional gas reservoirs fill from the top down. Researchers will explore whether gas pressure produces fractures that open pathways in which the gas flows from the bottom up. Another possibility is that gas migrates along fault lines. Gas could also move due to diffusion, where differences in pressure move the gas from areas of higher pressure to areas of lower pressure. By analyzing the composition of the gas taken from many samples, researchers identified the mechanisms that force the gas to move. Models were developed using this information to help predict underground areas where the most gas should be located. The composition of the gas in three different major tight sands fields was documented via intensive sampling. Hydrous pyrolysis experiments, which break down compounds via heat and water, were conducted to determine the composition of gas entering the subject areas. This provided the information needed to model the different ways the tight sands fill with gas, enabling researchers to simulate in the laboratory processes that occur naturally underground. Gas samples were taken from the Jonah Field in southwestern Wyoming; Mamm Creek Field in western Colorado; and the Greater Natural Buttes Field in northeastern Utah. Gas composition was mapped across the fields to determine the structure, stratigraphy, temperature, and connectivity.

Accomplishments: The researchers completed mud gas sampling and analysis and generated a list of findings. In general, the findings indicated that gases in the Jonah Field were dry at the top and became wetter and lighter as the samples were taken deeper. Dry gas is primarily methane; wet gas has other types of gas mixed in with methane. Mamm Creek samples were wet at the top and became drier and heavier with depth. The samples taken at the Greater Natural Butte field did not show a trend in composition. Although the overall composition of gases was similar in all three fields, the composition in the Mamm Creek and Greater Natural Buttes Fields was similar to that of coal-rich formations.

Ongoing Activity and Future Plans: This project is complete and no further activities are planned.

Lessons Learned: Researchers learned that the movement of gas in a tight sands geological setting is not fully explained by self-fracturing, diffusion, and migration through faults. More modeling is needed to determine how gas moves in these formations; however, because the composition of the gases in the fields is known, researchers can predict where to drill new wells with greater certainty.

Benefits: Enhancing predictive methods to exploit tight-gas-sand reservoirs may help researchers determine if tight-gas fields are simply "sweet-spots" in a continuous accumulation of gas, indicating the presence of large accumulations of gas resources, or if they are conventionally-trapped accumulations in very low-permeability rock, indicating much lower accumulations of gas resources. Knowledge gained from this project provided much-needed information about the composition of gas in tight sands, which should aid in predicting well productivity.

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Project Number: 07122-09

The final report for this project is available at: https://www.dropbox.com/sh/a2t72b5g0pjasl5/tyO70tXWlP.

Petrophysical Studies of Unconventional Gas Reservoirs Using High-Resolution Rock Imaging—Lawrence Berkeley National Lab; 12/2008-11/2012

Objective: The mechanisms that block gas flow in tight rock formations are not fully understood. The focus of this project was to determine the physical mechanisms that limit gas recovery in tight rock formations and find ways to increase the volume of gas recovered. The project objectives were to gain a better understanding of the key factors that influence the rate and ultimate level of gas recovery and subsequently investigate methods of changing the formation properties volumetrically to optimize production in space and in time.

Research Conducted: Researchers used the Advanced Light Source facility and Focused Ion Beam technology at Lawrence Berkeley National Laboratory to analyze the high-resolution images of gas-bearing shale rocks in order to estimate gas shale and tight sands flow capabilities under different conditions (including in situ conditions). The research team investigated the effect of pore-space geometry in different rock formations on flow properties, including absolute and relative permeabilities, capillary pressure, and Klinkenberg coefficient.

Accomplishments: In order to gain a better understanding of the pore space in shale and tight sands, researchers obtained 3D images using a scanning electron microscope coupled with a focused ion beam. Shales imaged included Collingwood, H2, Barnett, Utica, Eagleford, Marcellus, Montney, New Albany, and Kern. Imaging indicated a rich variety of gas-shale structures; however, it also revealed very low permeability. Images of Barnett shale show pores in organic and mineral phases. Other images of New Albany shale show almost no porosity even at very high resolution. Techniques used to image tight sands included optical microscopy, X-rat, CT, and SEM. Tight sands are typically densely-packed small grains with little porosity. In these samples, the pores were frequently filled with much smaller clay particles, which left almost no porosity. Other pores are a few microns wide and have a slit-like opening. Observations made in this project indicated that a model of gas flow to a fractured well best fit the low porosity of rock.

Ongoing Activity and Future Plans: This project is complete, and no future activities are planned.

Lessons Learned: The ability to achieve the required sample size needed for shale nanotomography was a challenge due to sample preparation and mounting issues. In addition, the resolution of current imaging tools is not yet high enough to adequately capture grain size. Due to these constraints, pore-scale simulations were done on computer-generated data. Researchers used computer modeling to determine the optimal pressure needed to yield highest volume of gas recovery.

Benefits: The 3-D images made during this project can be used to develop depositional models and link the petrophysical properties of the rock to the geology and geological history of the reservoir. A thorough and comprehensive study of existing unconventional gas-bearing formations will create a knowledge base for the development of emerging tools for increasing the productivity of gas wells by optimizing gas recovery techniques.

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Project Number: 07122-22

The final report for this project is available at: http://www.rpsea.org/media/files/project/af28af0a/07122-22-FR-Petrophysical_Studies_UG_Reservoirs_High-Resolution_Imaging-11-30-12_P.pdf.

Advanced Hydraulic Fracturing Technology for Unconventional Tight Gas Reservoirs—Texas A&M; 9/2008-9/2012

Objective: Current hydraulic fracturing methods in unconventional tight gas reservoirs have been developed largely through ad-hoc application of low-cost water fracs, with little optimization of the process. This work focused on developing modern technologies to understand the fundamentals and to optimize design of, fracturing process in tight gas formations. The goal of this project was to develop new methods for creating extensive, conductive hydraulic fractures in low permeability gas reservoirs as well as investigate gel damage resulting from hydraulic fracturing and its effect on fracture conductivity.

Research Conducted: Researchers conducted several experimental and theoretical studies. Yield stress measurements were made with and without breaker and related to the damage potential of fracturing fluids. Experiments to measure filter-cake thickness were carried out, and correlations were obtained between filter-cake thickness and leak-off under both static and dynamic conditions. An analytical model developed for the displacement of gel/filter-cake in a laboratory fracture was experimentally validated. A systematic experimental investigation was undertaken to consider in a holistic sense most of the factors that determine the final conductivity of a hydraulic fracture. These factors include reservoir properties, fracture fluid/proppant characteristics, and operational considerations (proppant schedule and flow-back rate). The effect of two-phase flow, proppant crushing, gel damage, yield stress, and fracture length on long-term gas productivity was investigated using a 3-D three-phase reservoir simulator. In addition, the flow of Herschel Bulkley fluids through a proppant pack was studied. Results from this part of the study can be incorporated into commercial reservoir simulators. Lastly, a tight gas advisor was developed to improve hydraulic fracture design practices.

Accomplishments: All the studies agreed that the yield stress of the broken fracture fluid is a key indicator of the optimal productivity of a hydraulic fracture. It was noted that when breaker is added to the fracture fluid, the yield stress decreases to a near-zero value, thereby aiding cleanup. In static experiments, filter-cake thickness was directly related to the leak-off volume. In dynamic experiments, the shear rate impedes the growth of the filter-cake and there is a quadratic relationship between the filter-cake thickness and leak-off volume.

Dynamic fracture conductivity tests were conducted to test the effect of some factors on conductivity. Based on the log-transformed dataset, the factors affecting conductivity—arranged in order of decreasing impact—were closure stress, polymer loading, flowback rate, presence of breaker, reservoir temperature, and proppant concentration. Increases in closure stress, flow back rate, temperature, and polymer loading were observed to have deleterious effects on fracture conductivity. In particular, at high closure stresses and high temperatures, fracture conductivity was severely reduced due to the formation of a dense proppant-polymer cake. Dehydration of the residual gel in the fracture appears to cause severe damage to the proppant conductivity at higher temperatures. Also, at low proppant concentrations, there is an increased likelihood of the formation of channels resulting in high fracture conductivities.

Simulation runs to test the important factors that affect cleanup in tight gas reservoirs resulted in similar conclusions regarding the high importance of proppant crushing (effect of closure stress) and gel damage. The project team also concluded that if the fracture fluid does not break completely and retains yield stress of 3-100Pa, then the fracture fluid would either clean up slowly or will never clean up when the dimensionless fracture conductivity is 10 or less.

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

Lessons Learned: Flow rates experienced in many shale wells result in velocities too low to remove some fracturing fluids. Understanding and designing around this issue will increase flow rates and recovery.

Benefits: The findings of this project will help engineers to optimize hydraulic fracturing treatment design in tight gas reservoirs.

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Project Number: 07122-33

The final report for this project is available at: http://www.rpsea.org/files/2885/.

Novel Fluids for Gas Productivity Enhancement in Tight Formations—University of Tulsa; 9/2008-7/2012

Objective: In the continental United States and many parts of the world, large volumes of natural gas are available in very difficult to produce formations such as shales, tight sands, coalbeds, and hydrates. Fracture stimulation is most commonly used to recover gas from low permeability unconventional formations. Invasion of aqueous fracturing fluids during stimulation operations can reduce the relative permeability to gas resulting in a "block" that significantly reduces the productivity of the well. This project was intended to address key issues for enabling recovery from these resources through improved completions and stimulation fluids. The objective of this project was to develop novel fluids for remediation and fracturing by better understanding the impact of fluid properties on the performance of flowback of gas in tight gas wells.

Research Conducted: Researchers conducted experimental studies to remediate gas wells damaged by trapped gels by injecting dry gas, solvent, and isopropyl alcohol into small-scale models of fractured rock filled with proppants. One model was packed sand, and another was tight gas sandstone rock that was split in half and packed with sand. The sandpack and fracture-pack were injected with gel fracturing liquid then the liquid was removed, simulating actual displacement techniques commonly used. Both the sandpack and fracture-pack models were treated with dry gas and alcohol.

Accomplishments: Experiments on sandpacks and fracture-packs show that dry gas treatment leads to cleanup of gel damage by removing the water content of the gel through evaporation process, thus reducing gel saturation.

The improvement in ultimate gas flow rate during flow-back in sandpacks and fracturepacks due to dry gas treatment is several times higher than that obtained by the viscous displacement method alone.

Alcohol treatment of the damaged fracture-pack results in a marginal improvement in the gas flow rate during flow-back. However, when the alcohol treatment is combined with a dry gas treatment, gas flow rate recovers faster and to greater values compared to dry gas treatment alone.

Experiments on the phase behavior of the air-gel system show that the vapor pressure of water in the gas phase is not affected until very high mass fraction of polymer is achieved. It is unlikely that such high mass fraction can be achieved in the field.

The isopropyl alcohol-gel phase behavior experiment shows a complete redistribution of water into alcohol from the gel phase resulting in only polymer structure residue, which shows that alcohol treatment has the potential to remove gel damage by removal of water.

A model based on drying front propagation was able to predict gas flow rate recovery during dry gas treatment, and the predictions compare well with experimental observations. The model may be scaled up to reservoir conditions in order to make quantitative predictions for field applications of dry gas treatment.

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

Lessons Learned: After the successes achieved in the lab, the project team scheduled field tests on a well in Merna Field, Wyoming; however, researchers determined that, based on the current price of gas, it would not be economical to conduct testing after calculating that it would take more than four years to recover the cost of treatment for the planned well.

Benefits: The results of this study will enable better selection of treatment fluids to remediate non-performing tight gas wells as well as strategies for selecting fluid additives to fracturing fluids for future applications.

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Project Number: 07122-36

The final report for this project is available at: http://www.rpsea.org/files/2886/.

Improvement of Fracturing in Gas Shales—University of Texas; 4/2009-8/2012

Objective: Shale reservoirs must be fractured hydraulically to produce at an economic rate. Long propped fractures are needed to maximize productivity. Slick water fracturing with sand produces these long fractures but is only effective near the well bore because the proppants settle and do not move through the fracture. Gels can be used, but they damage the fracture surface. The goal of this project is to develop non-damaging, productivity enhancing, low environmental impact fracturing techniques for gas shale reservoirs and demonstrate their performance through field tests.

Research Conducted: Lightweight proppants were evaluated because they settle slowly during fracturing. Foams were tested as the fracturing fluid because they minimize water use and decrease proppant settling. Experiments were conducted with different substances including polymeric proppant, resin with ground walnut hulls, resin coated with ceramic, and sand. All the substances differed in size, density, roundness, and porosity. The first was the broadest, the second was the largest, and the third the narrowest and most brittle. Researchers subjected these samples to stress and strain in the laboratory, testing their strength and stability to determine when they will fail and become crushed into very fine particles called fines. In addition, researchers conducted experiments on foam samples using three different surfactants, which allow the foam to spread. Researchers measured the stability of these foam samples under stress, analyzing attributes such as bubble size and height, and time it took the foam to collapse.

Accomplishments: Test results indicated that the polymeric proppant mixed with sand performed best in stress environments similar to Barnett shale. Both the polymeric proppant and the resin with walnut hulls produced a small amount of fines when subjected to high stress. The resin coated with ceramic produced a large amount of fines. Foams without gel increased both the length of the propped fractures and gas productivity compared to water by carrying sand further into the fractures.

Ongoing Activity and Future Plans: The project is complete, and no further activities are planned.

Lessons Learned: Although foam places sand more uniformly than water, the fracture length opened by foams is shorter than that created by water due to the increased thickness of the foam. This means that foam is superior to water in gas reservoirs that are more permeable.

Benefits: This project demonstrated the best proppant and foam to transport the proppant for use in hydraulic fracturing. If proven in the field, these discoveries will help increase gas production and make the fracking process more environmentally-friendly.

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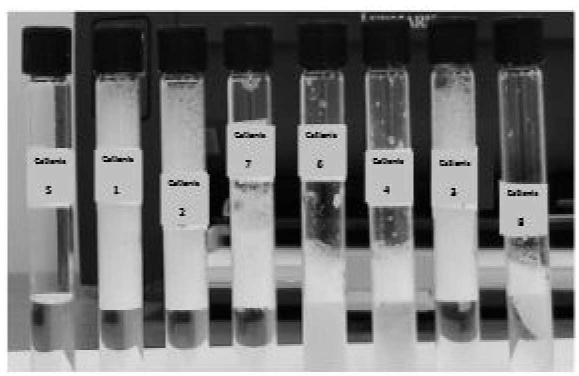
Project Number: 07122-38

The final report for this project is available at: http://www.rpsea.org/media/files/project/28e6c72c/07122-38-FR-Improvement_Fracturing_Gas_Shales-08-01-12_P.pdf.



Foams produced by the 1% cationic surfactant solution with no other additives.

Improved Reservoir Access through Refracture Treatments in Tight Gas Sands and Gas Shales—University of Texas; 8/2008-6/2013

Objective: Gas reservoirs require continuous drilling and fracturing to stay productive. Refracturing is more economical than drilling new wells, but the record of success has been mixed. This is partly because the decision to refracture is based both on information available at the surface and production statistics. The goal of this project was to develop a methodology to help determine a well's potential for refracturing and improve re-fracture designs. Researchers will measure stress reorientation and better characterize the role it plays in refracturing.

Research Conducted: Researchers studied the extent and timing of stress reorientation, including the stresses caused by the injection of fluids through experimentation and modeling. A new method of sequencing fractures in horizontal wells, called the Texas Two-Step method, was simulated using data from 300 tight gas wells in the Codell formation of the Wattenberg field in Colorado, including 170 refractured wells. This formation is composed of low-permeability, clay-rich sandstone. In addition, three fracturing sequences were investigated in Barnett shale: consecutive fracturing, alternate fracturing, and simultaneous fracturing of adjacent wells (zipper-fracs).

Accomplishments: Researchers found that opening fractures increases the stress in the direction of the opening. Subsequent fractures move away from previous fractures vertically, leading to longitudinal fractures. Reorientation increases with the number of fractures created and is dependent on the fracturing sequence. With this knowledge, researchers identified minimum and recommended fracture spacing for vertical, fractured, and horizontal wells. Researchers found that stress reversal occurs in production wells but not injection wells. They also found that simulation of Barnett shale fracturing sequences indicated that consecutive fracturing decreased reservoir drainage; however, alternate fracturing and zipper-fracs improved stimulation performance in horizontal wells. Minimum fracture spacing for consecutive fracturing and zipper-fracs was 230 feet, and alternative fracturing was 325 feet. The recommended fracture spacing was 600 feet for consecutive fracturing, 340 feet for alternate fracturing, and 400 feet for zipper-fracs.

Ongoing Activity and Future Plans: The project is complete and no further activities are planned.

Lessons Learned: Simulation in multiple-lateral horizontal wells suggests that different fracturing treatments should be used in the middle well instead of the outside wells. Researchers also found that the optimal duration for refracturing unconventional resources is usually months to years.

Benefits: Re-stimulation extends the life and productivity of existing gas wells. The knowledge gained through this project improved the selection of wells to re-stimulate and boosts the performance of refracture treatments in gas shale and tight gas sands, increasing well productivity and profitability.

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Project Number: 07122-41

The final report for this project is available at: http://www.rpsea.org/projects/07122-41/.

Novel Gas Isotope Interpretation Tools to Optimize Gas Shale Production—Caltech Goddard; 8/2009-2/2013

Objective: Gas is stored in shale as bound gas within rock and as free gas in pore spaces or fractures. During the gas production process, gas held in reservoirs is released. This project seeks to differentiate between bound and free gas as a way to predict the volume of gas reserves. The overall objective of this work is to develop special natural gas isotope interpretation tools for predicting, monitoring, and optimizing shale gas production. To accomplish this, researchers planned to deploy a gas isotope spectrometer and develop a user-friendly interpretive tool to measure gas potential.

Research Conducted: Based on the concept that smaller molecules move faster through rock than larger molecules, researchers sought to develop a field technique and equipment where both C and H isotopes for methane can be determined in real time. The change in isotopes enables researchers to track the free to bound gas process. Through theoretical and laboratory studies, researchers developed a real-time natural gas isotope analyzer (NGIA), based on advanced chromatography-infrared spectrometry technology, by modifying an infrared spectroscopy sensor. The NGIA instrument was deployed at Devon's Barnett shale reservoir in Rhome, Texas in October 2011, and field testing of the instrument was conducted through August 2012. Field data helped hone the instrument, enabling a more accurate forecasting of gas shale production.

Accomplishments: The first-ever field-deployable methane isotope analyzer was developed in this project that provides high-frequency and high-precision in-situ methane gas carbon isotope measurement. Researchers demonstrated the effectiveness of the NGIA through laboratory and well testing results. They were able to correlate methane isotope fractionation changes with the gas shale production decline curve.

Ongoing Activity and Future Plans: This project is complete and there are no future plans.

Lessons Learned: Much effort went into making the equipment ready to be deployed in the field. It needed to be able to withstand large temperature swings, for example, and include features such as remote data access, remote system restart of the software, and remote automatic restart in case of power failure.

Benefits: The NGIA provides a user-friendly way to estimate the potential recovery rate of gas in these unconventional resources; these estimates lead to more efficient and economical production.

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Project Number: 08122-15

The final report for this project is available at: http://www.netl.doe.gov/File%20Library/Research/Oil-Gas/Natural%20Gas/shale%20gas/08122-15-final-report.pdf.

Stratigraphic Controls on Higher-Than-Average Permeability Zones in Tight Gas Sands, Piceance Basin—Colorado School of Mines; 7/2009-6/2012

Examples of fluvial facies from White River and Little Horse Draw in the Piceance Basin, CO.

Objective: The unconventional tight-gas sandstone in the Piceance Basin, CO offers enormous potential gas resources. One of the challenges to tapping this potential is that some of the sandstones in the basin have very low permeability (<0.1 md), and this low permeability necessitates expensive hydraulic fracturing to access the reservoir. Also, productive Williams Fork sandstones are extremely heterogeneous fluvial to marginal marine reservoirs that have very low permeability that typically require expensive hydraulic fracturing with 10 - 20 acre well spacing to produce. The higher-than-average permeability zones can be tapped more economically, but these zones are complex and poorly understood. Several geologic controls—including controls on reservoir quality, fracture development and compartmentalization such as depositional environment, diagenesis, mechanical rock properties and strain—impact permeability. This project created a stratigraphic framework using outcrop and subsurface data. The resulting framework can be used to better understand the stratigraphic controls impacting tight-gas sand.

The hope is that this framework can be used to identify reservoir "sweet spots."

Research Conducted: Through fieldwork and field observation, the research team gathered data on outcrops and analyzed it. The team paid special attention to open marine and tidal influence in the outcrop as indications of regional flooding surfaces. This outcrop data was correlated with subsurface well log data.

Accomplishments: Through this study, the research team identified 34 different lithofacies (i.e., distinct rock units in outcrops) within the lower Williams Fork study area. They associated these lithofacies with nine unique lithofacies associations that could be represented on the stratigraphic map. The team also identified depositional sequences and corresponding fluvial layers not identified in previous studies of the region. The identification of tidal deposits through this study has strengthened the sequence-stratigraphic knowledge of the lower Williams Fork Formation.

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

Benefits: Companies looking to conduct gas exploration in the Piceance Basin can correlate the outcrop data provided from this study with subsurface characterizations to improve production.

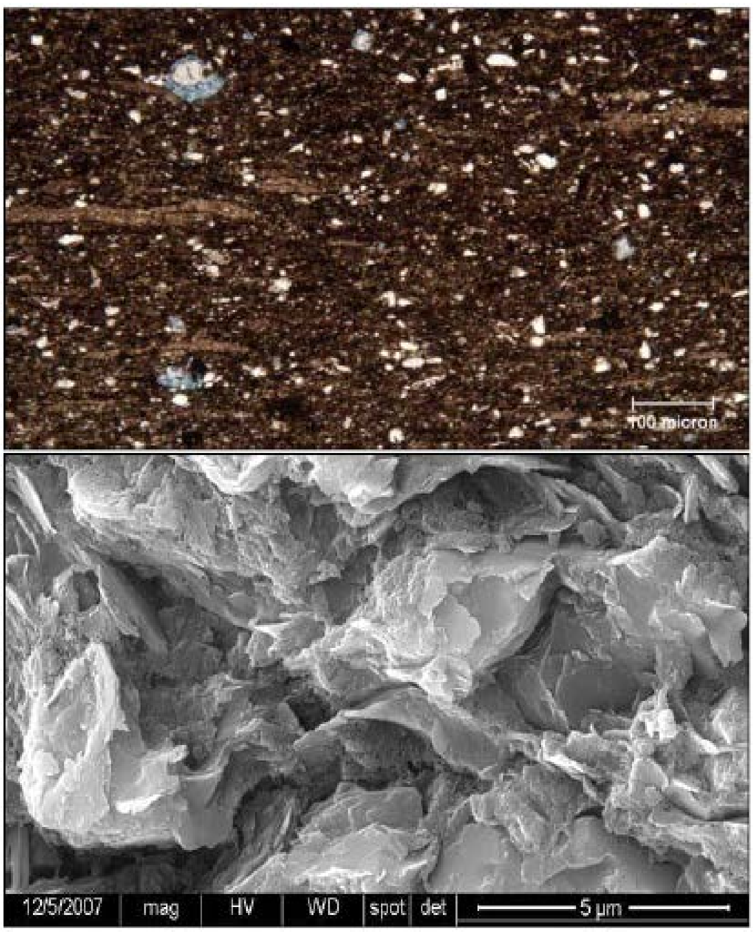
Key Contact: Dr. Jennifer L. Aschoff and Sarah Edwards, Dept. of Geology and Geological Engineering, Colorado School of Mines

Project Number: 08122-40

The final report for this project is available at: http://www.rpsea.org/files/3073/.

Sustaining Fracture Area and Conductivity of Gas Shale Reservoirs for Enhancing Long-Term Production and Recovery—Texas A&M; 9/2009-5/2013

Objective: The loss of fracture area and fracture conductivity have a significant impact on shale gas productivity. The objective of this project was to study the causes of fracture area loss and fracture conductivity, identify the parameters (including optimal proppants, fracture fluids, and pumping schedules) necessary to maintain productivity, and propose long-term strategies for retaining fracture area and ensuring conductivity.



Representative thin section (top) and SEM (bottom) of the best reservoir quality rock in the Marcellus shale.

Research Conducted: The researchers studied the properties of different types of shale (including Marcellus, Barnett, and Haynesville), reservoir geology, mechanical properties, in-situ stress, and rock-fluid interactions. As part of the study, they looked at the impact of "creep" (deformation that happens over time under a constant load) on material properties. The researchers also looked at the loss of surface area in fracture networks and the fracture conductivity of both propped and unpropped features. The study included simulated field testing of a large-scale block of shale.

Accomplishments: The researchers completed over 150 fracture conductivity tests on characteristic shale cores and measured a variety of factors, including stress depletion effects and rock-fluid interaction. The findings from these studies and results from an industry best practices survey led to a series of recommendations for an improved workflow for fracture design, rock characterization, and production of tight gas shales.

Ongoing Activity and Future Plans: This project is complete, and no future activities are planned.

Lessons Learned: A number of findings resulted from the project including:

- Fracture conductivity increased significantly when proppant was added to the fractures. Also, stress sensitivity was reduced.
- The loss of surface area and fracture conductivity during production are complex problems with no easy solution because many different properties are involved.
- Operators are still looking for a single solution to lost fracture area and conductivity.

Benefits: This project yielded recommendations for creating a workflow that improves well productivity and decreases the loss of production over time. The final report offers suggestions for the workflow, including:

- Characterization of the geologic system as a first step in the workflow.
- Classification of rock type units with similar texture and composition and corresponding similar material.
- Evaluation of comprehensive material properties representative of each rock type.

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Project Number: 08122-48

The final report for this project is available at: http://www.rpsea.org/files/3052/.

Multiazimuth Seismic Diffraction Imaging for Fracture Characterization in Low-Permeability Gas Formations—University of Texas at Austin, Bureau of Economic Geology; 10/2009-11/2013

Objective: The ability to detect and exploit fractures in low-permeability gas formations is key to long-term shale gas production. Natural fractures that are significant to production are difficult to detect with conventional seismic techniques (which use expensive, multicomponent seismic surveys based on reflection). Novel approaches to detection using diffraction are needed so that fractures below detection limits can be identified. One of the challenges of identifying potentially-productive reservoirs is being able to predict diagenesis (i.e., sedimentary rock changing from one stage to another). The degree of diagenesis impacts whether or not a fracture may be partially sealed, and sealed areas are less productive. This project seeks to develop advanced technologies and techniques that will improve detection and shale characterization. This project uses seismic diffraction imaging technology and improved wireline conveyed sidewall core analysis of structural diagenetic fracture surrogates for detection, characterization, and prediction.

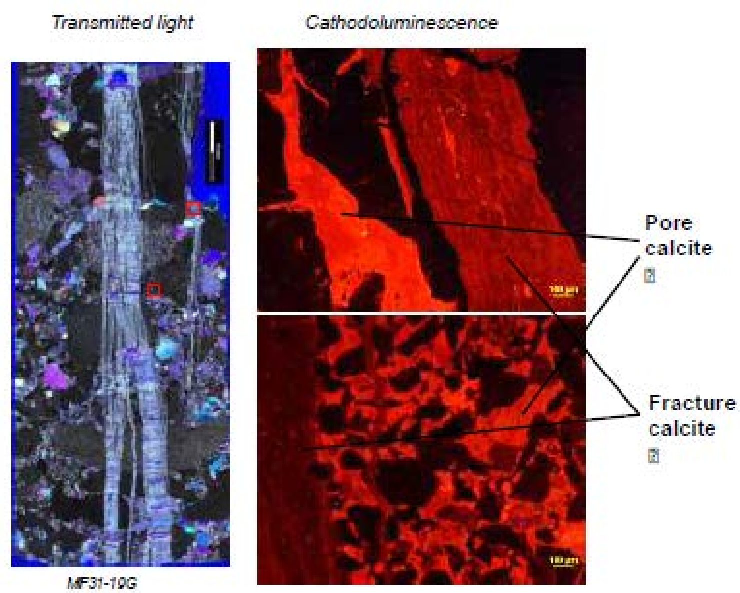
Research Conducted: The researchers approached the problem of fracture detection through investigations of current techniques and modeling. Key research tasks included investigating novel techniques that narrow the observation gap between traditional seismic techniques and fracture size distributions that can be observed in core and image logs; developing new modeling approaches for fracture networks; looking at existing techniques for prediction fractures using fracture population characteristics; and considering what fracture population characteristics make them more detectable through seismic detection methods.

Accomplishments: The researchers were able to generate and verify realistic fracture patterns using a geomechanical model and some outcrop samples as guides. The results were measured against outcrop patterns of analogous reservoirs. The researchers demonstrated that fracture diagenesis may seem heterogeneous difficult to predict, but that the degree of cement infill and fracture cement mineral composition (two aspects of reservoir seismic response) are predictable using proxy techniques such as the degradation index and applying a fundamental understanding of reservoir diagenetic processes during burial.

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

Lessons Learned: Fracture diagenesis tends not to be uniform across a reservoir, but some key aspects (e.g., the degree of cement infill and fracture cement mineral composition) can be predictive. Proxy techniques such as degradation index can be used to help predict where and to what extent diagenetic processes have occurred.

Benefits: Traditional methods of seismic detection use reflection to identify seismic waves. This project delivered a more cost-effective, potentially powerful new fracture detection technique using diffraction. Diagenetic changes are more effectively detected with diffraction than with reflection seismic waves. Being able to predict the diagenetic overprint of a fracture means being able to predict potential seals. The use of this technique can reduce the costs associated with exploration and increase the likelihood that exploratory drilling will successfully find productive reservoirs.



Transmitted light and cold-cathode luminescence images of carbonate fracture.

Key Contact: Dr. Sergey Fomel, Professor & Dr. Peter Eichhubl, Research Scientist; Bureau of Economic Geology; Jackson School of Geosciences; University of Texas at Austin.

Project Number: 08122-53

The final report for this project is available at: http://www.rpsea.org/media/files/project/4dd2222c/08122-53-FR-Multiazimuth_Seismic_Diffraction_Imaging_Fracture_Low-Permeability_Gas_Formations-06-17-14_P.pdf.

Characterizing Stimulation Domains, for Improved Well Completions in Gas Shales—Higgs-Palmer Technologies, LLC; 3/2011-12/2013

Objective: Gas well operators need to have tools and methods for characterizing reservoirs and predicting fractures. The main objective of this project was to develop a software prototype called DomAnal that would allow operators to better characterize a reservoir.

Research Conducted: The researchers conducted a series of modeling studies looking at shear failure, porosity, permeability, and other factors related to fracture networks. These studies informed the researchers' choices on fields to include in DomAnal as they developed it. The researchers used DomAnal to analyze well and reservoir data from five Fayetteville shale wells.

Accomplishments: The researchers successfully developed and deployed a new fast analytic tool—DomAnal—that provides operators with a reliable model that can serve as an alternative to traditional models, which tend to be more rigid and slower. The DomAnal prototype that resulted from this now complete project uses a two-step process. The first step involves a geomechanical model that uses microseismic data to help anticipate injection permeability; the second step gathers data for analysis of potential gas rate decline, a measure that can be used to predict production permeability. DomAnal combines these two measures (injection permeability and production permeability) and gives operators the quick-turnaround data they need to pick the right proppant size and timing.

Ongoing Activity and Future Plans: Though this project is complete, the results of the project are still being disseminated and vetted by researchers and industry. The DomAnal software is available and being distributed. Operators can download the DomAnal software and user manual from the RPSEA website at: http://www.rpsea.org/projects/09122-02/. The results have been shared at multiple conferences and workshops.

Lessons Learned: This project joined two models for better characterization of the volume of the microseismic cloud. One lesson learned through this process was that fracture networks are complex; the researchers determined that proppant is a small portion (<4%) of the total fracture network volume. They also discovered that in deeper wells natural fractures tend to be spaced further apart and tend to be wider than in shallower wells.

> "Unlike most hydraulic fracture stimulation models which largely predict planar fracture geometry, DomAnal provides a unique, yet simple, modeling solution to predict fracture behavior and well production performance for wells that are stimulated using low viscosity fluids for the creation of complex fractures. Considering that producers are using slickwater to stimulate many shale, tight gas and oil reservoirs, this methodology is very compelling."
>
> Kirby Nicholson, P.Eng.
> Staff Engineering Specialist
> Perpetual Energy Inc.

Benefits: The DomAnal software created through this project will help improve well completion design. Since well completion is a critical final step prior to production, improvements in well completion design can lead to more productive wells. Public dissemination of results will help to advance overall industry understanding of treatment design relationship with productivity.

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Project Number: 09122-02

The final report for this project is available at: http://www.rpsea.org/media/files/project/2c780dc0/09122-02-FR-Characterizing_Stimulation_Domains_Improved_Well_Completions_Gas_Shales-01-22-14_P.pdf.

Improved Drilling and Fracturing Fluids for Shale Gas Reservoirs—University of Texas at Austin, Bureau of Economic Geology; 12/2010-6/2014

Objective: Because gas shale plays often have a high clay content, oil-based muds are used in drilling more often than water-based mud to reduce wellbore stability problems. This significantly increases drilling costs and the environmental footprint. Chemical shale inhibitors are used in both oil-based mud and water-based mud to prevent the fluid from diffusing into the shale matrix and to stabilize the wellbore. The use of the oil-based fluids and chemical inhibitors add substantially to the cost of drilling. This project seeks to develop materials and methods that will significantly reduce drilling and completion costs while maximizing gas well productivity in shale gas reservoir and to develop novel drilling fluids for water-sensitive shale.

Research Conducted: Researchers developed a systematic approach to investigate the interaction of organic-rich shale with water-based drilling and fracturing fluids. Shale measurements were taken to characterize shale mineralogy, native water activity, swelling parallel and perpendicular to bedding planes, Brinell hardness, P-wave and S-wave velocities, and compressive strength. They then measured changes in hardness and acoustic wave velocities before and after exposing shale samples to water-based fluids. Shale swelling was determined in two directions simultaneously. X-ray diffraction experiments were also performed to determine shale mineralogy, and native water activity was determined with the use of controlled humidity environments.

Permeability measurements were taken for preserved shale core samples in contact with brines with the native water activity. The shales were then exposed to brine solutions containing nanoparticles, and permeability was measured again and found to be reduced by more than two orders of magnitude.

Researchers also characterized the behavior of gas shale in contact with drilling and fracturing fluids currently in use, then demonstrated that the use of a novel nanoparticle-based drilling fluid resulted in a dramatic reduction in the reactivity of the shale with the drilling fluid.

Accomplishments: The project has provided a systematic methodology for preparing shale samples and measuring their permeability in a preserved state, and the researchers have developed temperature-stable nanoparticle-based drilling fluids. The project data showed that these cost-effective water-based fluids with nanoparticle additives can effectively reduce water and ion invasion into shales. Additionally, several muds have been designed (in collaboration with MI Drilling Fluids) that may be suitable for use in the field under elevated temperature conditions.

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

Lessons Learned: Researchers learned that flow characteristics of the nanoparticle-based fluid greatly depends on the kind of nanoparticle used, as well as the temperature and the chemicals used in the mud.

Benefits: For industry to invest in shale gas play development, the cost of drilling and fracturing horizontal wells must be reasonable; however, production decline often necessitates the drilling of new wells to maintain production. Nanoparticle-based fluids developed through this project will lead to a reduction in cost and environmental footprints associated with drilling and fracturing and could make shale gas development more attractive to developers. Finally, the use of such fluids provides significant cost savings when drilling water-sensitive shales with water-based fluids and reduces the potential of wellbore collapse.

Key Contact: Mukul Sharma, University of Texas at Austin, 512-471-3257, msharma@mail.utexas.edu.

Project Number: 09122-41

The final report for this project is available at: http://www.rpsea.org/media/files/project/e6b62644/09122-41-FR-Improved_Drilling_Fracturing_Fluids-09-03-14_P.pdf.

Diagnosis of Multiple Fracture Stimulation in Horizontal Wells by Down hole Temperature Measurement for Unconventional Oil and Gas Wells—Texas A&M University; 11/2011-9/2014

Objective: Production logging tools or fiber-optic sensors are often used to generate temperature distribution data and diagnose a multi-stage fractured well stimulation. However, transient temperature data may provide better insight into fracture performance and allow for optimized fracture design. This project will develop novel approaches for using temperature data to diagnose stimulation treatments, estimate fracture geometry, and evaluate fractured well performance in unconventional tight sand and shale reservoirs. The ultimate goal is to improve the efficiency of multiple fracture stimulation.

Research Conducted: A semi-analytical slab-source model was developed and used to predict the well performance of a hydraulic fractured well system. As natural fractures are heterogeneous, a discrete fracture network was adopted. To test the model, predictions were made for the performance of multiple stages of horizontal well fractures, considering the influence of the fractures on subsequent and previous fractures. The program was able perform up to 20 fractures at a time.

The existing fractal discrete fracture network (FDFN) model was originally developed to incorporate scale-dependent data, including outcrop, log, and core data. Researchers successfully combined this model with the slab source model to reproduce the realistic natural fracture patterns.

Flow and thermal models were also created for horizontal wells with transverse fractures. The scheme was divided into a horizontal wellbore and a reservoir with multiple fractures. The wellbore and thermal model was formulated based on mass, momentum, and energy balance. Numerical reservoir simulation was used to address flow, while the thermal model was formulated with a transient-energy balance equation.

The reservoir flow and thermal model was coupled with the wellbore model to predict the temperature distribution in a horizontal wellbore. Modeling results suggest two primary mechanisms influence thermal problems: head conduction by the formation heating or cooling effects at non perforated zones, and mixing effects of wellbore fluid with reservoir inflow at fracture locations.

Accomplishments: Once researchers confirmed the model worked, a more realistic representation of a natural fracture was successfully modeled. The test involved 20 stages of hydraulic fractures with 60 natural fractures. Researchers believe the method is flexible and can be easily applied to real-world wells.

Work under this project included developing a model to calculate the heat transfer in the formation, fracture, and wellbore system while considering small changes in temperature by including Joule-Thompson cooling effects. The results suggest transient temperature behavior should be considered when estimating the fracture initiation points, number of created fractures and fracture conductivity.

Ongoing Activity and Future Plans: Although research has concluded for single-phase modeling and during-production modeling, work continues on two-phase modeling, during-fracturing, and shut-in models. Field data has been collected for model validation and application and an algorithm of inversion has been investigated to determine the most efficient and robust approach. Future work will also involve reducing the number of sources used and incorporating a plane source method for natural fractures.

Lessons Learned: To simulate a more complex occurrence of natural fractures, reducing the number of sources or adopting a new matrix solving algorithm is necessary.

Benefits: This project may benefit producers and stakeholders by ultimately influencing more accurate fracture simulation, which would lead to decreased costs and increased production.

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Project Number: 10122-43

This project is ongoing; therefore, the final report is not yet available. Additional project details are available through the RPSEA website at: http://www.rpsea.org/projects/10122-43/.

Conductivity of Complex Fracturing in Unconventional Shale Reservoirs—Texas Engineering Experimental Station; 6/2013-5/2015

Objective: Researchers will conduct a systematic experimental study of fracture conductivity in shale oil and gas formations. Efforts will focus on the conductivity behavior in the Barnett shale, the Fayetteville shale, and the Eagle Ford shale.

Research Planned: Research into fracture conductivity behavior in shale formations will be studied with the application of newly-developed fracture conductivity testing procedures that allows for better simulation of the processes that occurs in high-rate, low proppant-concentration fracturing. Both propped and un-propped fracture conductivity will be examined, and the effect of proppant type, size, and concentration will be analyzed.

The testing procedure involves pumping a slurry composed of fracture fluid with proppant through or packing proppant into an American Petroleum Industry-modified conductivity cell before measuring conductivity with back-flow gas under conditions designed to simulate flow in fractures after closure. The same back-flow procedure will be used to study unpropped fracture conductivity. Additionally, outcrops and cores from shales will be collected and conductivity under different closure stresses will be studied by flowing gas or liquid through the test cell.

The effects of natural fracture, proppant type, size and loading, closure stress, and rock mechanic properties, on fracture conductivity will be carefully examined in the project. The ultimate goal is to understand fracture conductivity behavior in order to optimize fracture stimulation design, in shale formations.

Results-to-Date: Core samples have been collected from Barnett shale, Eagle Ford Shale, Fayetteville shale and Marcellus shale. Conductivity measurements of Barnett, Eagle Ford, and Fayetteville shales are complete. Conductivity measurements have been done and rock mechanics properties have been measured for Barnett shale and Fayetteville shale.

Ongoing Activity and Future Plans: Novel procedures and improved experimental apparatus for measuring fracture conductivity will be developed. Comparisons about conductivity behavior among the three shale formations will be analyzed and compiled from the finding and experimental observations will be compared with reported production observations so researchers can confirm the findings, explain the causes of failures of fracture treatments and unexpected declines of production performance, and provide guidelines for future fracture practices in these shale formations.

Lessons Learned: Current understanding of complex fractures is limited to inferred fracture geometries. The tools designed for hydraulic fractures and predicting their performance for other formations do not apply, and new software solutions specifically for shale reservoirs are limited.

Benefits: This project will help diagnose hydraulic fracture conductivity; guide operators in optimizing their hydraulic fractures to maximize shale recoverable reserves; and optimize hydraulic fracture design based on the performance prediction with field application examples.

Key Contact: Ding Zhu, Texas A&M University, 979-458-4522, ding.zhu@pe.tamu.edu.

Project Number: 11122-07

This project is ongoing; therefore, the final report is not yet available. Additional project details are available through the RPSEA website at: http://www.rpsea.org/projects/11122-07/.

Advanced Hydraulic Fracturing—Gas Technology Institute; 1/2013-12/2014

Objective: This collaborative project involves developing advanced methods and techniques for the design and execution of environmentally-safe and economically-efficient hydraulic fracturing. This project is a joint effort of researchers from University of California, Berkeley, Lawrence Livermore National Laboratory, Louisiana State University, and Octave Reservoir Engineering LLC and industry. WPX Energy, the industry partner, is providing background data and wells of opportunity for research quality field data acquisition.

The goal of this project is to minimize the amount of water and additives needed for fracture stimulation; optimizing this process will reduce the impacts from excessive use of fresh water, flow-back water, water disposal injections, and heavy truck traffic. Reducing water and additives also reduces costs associated with shale gas production.

Research Planned: This project includes acquiring and analyzing field data (e.g., borehole imaging, cross-well tomography, microseismic imaging, pressure monitoring, and production logging). The field data has been used to verify working hypotheses, calibrate analytic work, and hope optimize fracture stimulation.

Results-to-Date: As laboratory and analytic studies were being conducted, two extensive field data acquisition projects were implemented at multi-well pads in southwest and northeast Pennsylvania; using microseismic imaging, researchers mapped over thirty fracturing stages in two horizontal wells. One of the goals was to test variable rate fracturing, so this process was implemented in both test wells.

The results in the production logs demonstrated that variable rate stages had significantly higher production rates than conventionally-fractured stages.

Ongoing Activity and Future Plans: This project is ongoing. The end-products of this project include guidelines for environmentally-safe and economically-optimal fracture stimulation of shale and tight sand reservoirs; methods and techniques for high resolution microseismic data analysis; design requirements for the next generation microseismic data acquisition; and shale-specific production decline analysis software for hydraulically-fractured unconventional resources.

Lessons Learned: A comparison of production data from variable rate and conventional fracturing stages showed substantially higher production rates from variable rate stimulation than from conventionally fractured stages. A third field experiment (including microseismic imaging and production logging) is planned for late 2014; this experiment will verify the significant findings and help researchers fine-tune the procedure.

Benefits: This project will provide industry with guidelines for optimized fracturing processes; these improved processes will reduce water and addictive use, saving money and reducing potential environmental impacts.

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Project Number: 11122-20

This project is ongoing; therefore, the final report is not yet available. Additional project details are available through the RPSEA website at: http://www.rpsea.org/projects/11122-20/.

Petrophysics and Tight Rock Characterization for the Application of Improved Stimulation and Production Technology in Shale—Oklahoma State University; 6/2013-6/2015

Objective: Rock-fluid interactions in shale are still poorly understood. This project seeks to improve understanding of these interactions and refine the methods for petrophysical characterization, shale analysis, and fracturing fluid and additives selection. In order to accomplish these overarching objectives, researchers will develop techniques, workflows, and best practices for the petrologic and petrophysical characterization of shale; propose porosity and permeability measurement standards for shale; explore various techniques for characterizing the shale microstructure; and develop techniques to rapidly evaluate stimulation fluids and additives.

Research Planned: Core selection is complete, and the core analysis is underway. The researchers are completing petrologic characterization of the core samples. The researchers will test various techniques for characterizing porosity, permeability, and adsorption in shale and conclude their laboratory work with the characterization of fluid-rock interactions in shale. The results from this testing will be evaluated; based on the findings, the researchers will propose standards for evaluating stimulation fluids and additives. The end result of this project will be a comprehensive document including a best practices manual with proposed standards for shale petrophysics and tight rock analysis.

Results-to-Date: The researchers have measured methane adsorption on Albany and Woodford shales and pulse decay permeability on a Woodford shale core plug. They have also presented some results in a paper on petrophysical properties of Woodford Shale and impact wireline log signatures.

Ongoing Activity and Future Plans: The next stages for this project include testing the method for determining the size distribution of conducting pores on a tighter rock. The researchers will continue core analysis.

Lessons Learned: No lessons learned have been reported on this project to date.

Benefits: Once completed, this project will provide industry with the techniques, workflows, and best practices for shale characterization as well as standards for measuring shale porosity and permeability.

Key Contact: Jim Puckette, jim.puckette@okstate.edu, 405.744.6374

Project Number: 11122-63

This project is ongoing; therefore, the final report is not yet available. Additional project details are available through the RPSEA website at: http://www.rpsea.org/projects/11122-63/.

Measuring Fracture Density and Orientation in Unconventional Reservoirs with Simple Source Vertical Seismic Profiles— Bureau of Economic Geology, UT; 2/2011-4/2013

Objective: A remote seismic technology that can "visualize" the internal architecture of unconventional reservoirs and predict fracture orientation and density will be invaluable for characterizing tight sandstones, shale-gas units, and all unconventional resource plays. Current technology has demonstrated that shear (S) waves used to visualize reservoirs are more responsive to fractures than compressional (P) waves and that vertical-force sources (vertical vibrators, vertical impacts, shothole explosives) that produce S modes are lower cost, more abundant than horizontal-force sources, and usable over a wider range of terrains. There is strong interest in developing lower cost and more widely available S-wave vertical seismic profile (VSP) seismic sources because S-wave seismic data provide valuable fracture and stress information that is difficult, often impossible, to extract from P-wave data. The objective of this project was to develop and demonstrate a technology that uses vertical-force seismic sources combined with VSP to provide a seismic "log" of natural fracture orientation and density in unconventional reservoirs.

Research Conducted: The research team analyzed offset VSP data generated by vertical vibrators at two well sites: a Marcellus Shale prospect in northeastern Pennsylvania and a tight sandstone prospect in western Colorado. Following field-testing, the team analyzed the VSP data that describe downgoing direct-S wavefields generated by two types of vibratory seismic sources—a vertical vibrator that applies a vertical force to the Earth and a horizontal vibrator that applies a horizontal force to the Earth.

An extensive walkaround (WAR) VSP program was implemented at the Marcellus study site. Data from 70 WAR VSP stations were taken and recorded by a vertical array of sixteen 3-component geophones. The data were analyzed to calculate and compare the direct-S and direct-P radiation patterns produced by a vertical vibrator.

Data generated at the western Colorado site was used to demonstrate how the downgoing direct-S modes produced by a vertical vibrator can be used to estimate S-wave anisotropy, which is the standard calculation done by shale-gas operators to establish qualitative (not quantitative) indications of spatial distributions of fracture density around a VSP well.

Accomplishments: The 70 vertical-vibrator source stations utilized in the Marcellus Shale WAR VSP study produced data that provided convincing proof that direct-S modes were produced at each source station and allowed the velocities of these direct-S modes and their companion direct-P modes to be calculated in a full-azimuth circle around the VSP well. The resulting average velocities were used to calculate S-wave anisotropy so spatial variations in fracture density could be predicted in all azimuths away from the receiver well. These seismic-based estimates of S-wave anisotropy agreed with S-wave anisotropy values determined from a dipole sonic log acquired in the VSP well.

Ongoing Activity and Future Plans: This project is complete, and no future activities are planned.

Lessons Learned: While the team recommends the use of direct-S modes produced by vertical vibrators for determining "sweet spots" of fracture density, they do not recommend that these direct-S modes be used to estimate fracture orientation. The team's attempts to determine fracture orientation with vertical-vibrator direct-S modes led to ambiguous results.

Benefits: Simplifying S-wave seismic source activity by utilizing S modes created directly at the point where a vertical force is applied to the Earth's surface will result in less costly data acquisition, fewer environmental issues caused by source deployment, and utilization in a wide variety of terrains where horizontal-force sources cannot be deployed. The seismic technology developed in this study resulted in improved mapping of densities in unconventional reservoirs, thus addressing the objective of advanced visualization to enhance unconventional production. The technology was developed using VSP data acquired in shale-gas and tight-sandstone reservoirs, but it can be applied to any fractured reservoir, thus providing operators with better knowledge of fracture density that should result in increased oil production.

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Project Number: FE0005975

The final report for this project is available at: http://www.netl.doe.gov/file%20library/Research/Oil-Gas/Natural%20Gas/shale%20gas/fe0005975-final-report.pdf.

Integrated Experimental and Modeling Approaches to Studying the Fracture-Matrix Interaction in Gas Recovery from Barnett Shale—University of Texas at Austin, Bureau of Economic Geology; 10/2010-2/2014

Objective: The Barnett shale is a profitable gas play, but gas recovery rates are estimated to be as low as 10 percent of the estimated total recoverable gas in place. Recovery is hindered by the tight pore structure, which limits gas transport from the matrix storage to the stimulated fractured network. To enhance gas flow from the Barnett shale, engineers must have an understanding of the play's underlying connectivity; however, no systematic studies on the pore structure and connectivity are available in the published literature. This project seeks to remedy that by examining and evaluating the effects of low pore space connectivity on fractured-shale gas recovery as it relates to fracture-matrix interactions.

Research Conducted: Researchers approached the problem by characterizing the petrophysical properties (porosity, median pore diameter, pore-size distribution, permeability, etc.) of the Barnett shale play. Core samples from the Barnett Formation in the Ft. Worth area were obtained from five depths: 7,109 ft; 7,136 ft; 7,169 ft; 7,199 ft; and 7,219 ft. The samples were characterized with respect to porosity, particle and bulk density, permeability, and pore size distribution before being studied for water imbibition. The water imbibition experiments allowed researchers to monitor spontaneous water uptake over time on samples of different shapes and different bedding plane orientation.

In Barnett and other rock with sparsely-connected pores, the accessible porosity decreases as the distance from an edge increases (e.g., a fracture). Researchers measured that decrease to assess pore connectivity in the shale samples. Pore structure was also imaged with a scanning electron microscopy and other tools, and methane sorption and gas diffusion in crushed shale were determined at different water saturation levels. Pore-scale network modeling was completed to simulate experimental results and correlate the experimental findings on shale matrix pore connectivity and fracture-matrix interactions to gas production decline at field-scale.

Accomplishments: Results from this project showed the Barnett shale pores have a median pore-throat diameter of about 6 nm. Extremely low diffusion in the shale matrix can be attributed to these nanometer-sized pores in combination with low pore connectivity. Imbibition experiments suggested chemical diffusion in the shale play can likely be attributed to percolation.

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

Lessons Learned: Chemical diffusion in sparsely-connected pore spaces such as those found in the Barnett shale gas play is not well described by classical Fickian behavior. Percolation was thought to be the cause of the anomalous behavior, and researchers were able to confirm that in this project.

Benefits: This project fills significant knowledge gaps on pore connectivity as it relates to diffusive gas transport and recovery in fractured shale system. It should ultimately lead to approaches to enhance gas recovery in those systems.

Additionally, the findings on the effects of nano-scale pore structure on macro-scale fluid migration in hydraulically stimulated shale formations may lead to approaches that improve fluid productivity and allow for economic benefits related to unconventional resource utilization.

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Project Number: 09122-12

This final report for this project is available at: http://www.rpsea.org/media/files/project/71266a40/09122-12-FR-Integrated_Experimental_Modeling_Fracture-Matrix_Barnett_Shale-05-12-14_P.pdf.

Using Single-molecule Imaging System Combined with Nano-fluidic Chips to Understand Fluid Flow in Tight and Shale Gas Formation—Missouri University of Science and Technology; 2/2011-8/2014

Objective: Tight sand and shale plays hold natural gas in reservoir matrixes characterized by small pore throats and crack-like interconnectivity, with permeability ranges in the microdarcy (μD) or even nanodarcy levels. Fluid flow in this environment is poorly characterized, which makes stimulation design and production optimization difficult. The primary objective of this project is to fabricate nanofluidic chips that allow the study of multiphase flow on scale relevant to the size of pores in tight sand and shale formations.

Research Conducted: Researchers developed pore-scale numerical simulations to provide information about fluid movement and interaction including three dimensional motions of liquid-gas interfaces. Unique nanoscale chips were also fabricated and used in combination with a novel advanced single-molecule imaging system to allow for direct visualization of fluid flow behavior in nanochannels. Initial experiments on the fabricated chips were conducted on those containing 100 nm-depth channels; two-phase flow behavior and displacement in the nanochannels was investigated and characterized. Using chips with a range of pore sizes ranging from 30 nm to 500 nm, researchers also systematically studied the effect of pore size on flow and transport properties. The results of the nanofluidic chip and core flooding experiments allowed for verification and adjustment of the mathematical models.

Additionally, 18 experiments were conducted to study the effects of concentration, microchannel size, wettability, and shear rate on a solution of friction reducer (the primary component of hydraulic fracturing fluid) solution.

Accomplishments: Researchers designed and fabricated silicon and Pyrex® -based novel nanofluidic chips that can withstand pressures up to 1000 psi and temperatures up to 100°C. The chips consists of two micro-scale channels connected by a series of parallel nano-scale channels, and with its transparent matrix, allows for the direct observation of fluids interacting at nano-scale. This represents a major accomplishment that allows for multiphase flow testing on the micrometer and nanometer level, respectively. That approach has been demonstrated, as have the benefits, which include direct observation when the transparent chip is used in combination with the single-molecule imaging system and the ability to both control porous media properties and to make quantitative measurements on fluid saturations.

Ongoing Activity and Future Plans: Investigators will continue to analyze two-phase flow behavior in nanochannels,using newly fabricated nanofluidic chips and nano-scale network models. The gas slippage effect and residual fluid saturation will be characterized and pore-scale transport models for solutes and particles will be developed over the next year.

Lessons Learned: For the water/gas two-phase displacement experiments in nano-scale channels, flow patterns and residual water/gas saturations were different than those obtained from imaging. Three different flow patterns were detected when gas displaces water, while two types of flow patterns were found when water displaces gas. Although most of the flow patterns observed in the nano-scale channels were also seen in conventionally-sized tubes, a pattern for liquid displacing gas was unique. In nanotubes, a liquid core fills in the center of the tubes, leaving a cavity on the side of the channels. This flow pattern may be found only in the nanoscale channels and may cause higher residual saturations of gas.

Benefits: This research provides new technology that will advance understanding of fluid flow behavior in the nano-range channels. Economic benefits and more efficient production will also follow, as fluid flow behavior influences stimulation design, gas production optimization, and calculations of the relative permeability of gas in tight sand and shale gas systems.

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Project Number: 09122-29

This project was recently completed, and the final report is not yet available. Additional project details are available through the RPSEA website at: http://www.rpsea.org/projects/09122-29/.

A Geomechanical Model for Gas Shales Based on the Integration of Stress Measurements and Petrophysical Data from the Greater Marcellus Gas System—Penn State University; 11/2011-9/2015

Objective: The objective of this project is to develop a geomechanical model for the Marcellus gas system in the Appalachian Basin using collected stress profiles and log- and core- based petrophysical data from an area near three Marcellus gas well pads.

Research Conducted: Two Marcellus wells (Cornwall 1H and 2H) were monitored during a hydraulic fracturing operation using the BuriedArray^{TM} Near-Surface Microseismic System. Global Geophysical's patented Tomographic Fracturing Imaging (TFI) technology was used to identify 12 microseismic events. These events were analyzed and characterized as normal stress regime.

Open hole log data was also collected and used to constrain contemporary stress orientation and magnitude data. Researchers compared the constrained log data with the TFI-derived rose diagram and local joint mapping results, concluding that the reservoir-scale TFI diagram reflects fracture systems that were reactivated during the hydraulic fracturing process. Furthermore, results illustrate the interaction between the 1H and 2H wells through connections in the hydraulic fracture systems.

Accomplishments: Investigators uncovered a mechanical stratigraphy in the Appalachian Basin that indicates an interplay between fractures and in situ stress. The gas shales in the basin emit seismic energy from vertical zones. Those zones correlate with well-developed vertical joint sets. The TFI technique detects seismic energy coming from fractures with the same orientation as those seen in outcrops. The researcher's analysis employed TFI data with added detail that validates the TFI technique. In sections below the Onondaga Limestone, TFI takes place along zones that dip in much the same manner as splay thrusts, breaking from a regional detachment in the Silurian salt.

Ongoing Activity and Future Plans: The researchers will continue to collect and process the raw data in order to develop a geomechanical model for the Marcellus gas plays.

Lessons Learned: Analysis of the data collected suggested non-intuitive results: the most highly stressed layers—the Tully and Onondaga limestone—emit the least seismic energy. This reflects a lower fracture density that allows for the accumulation of the greatest elastic strain (i.e., stress).

Benefits: Geomechanical characterization of the Marcellus gas system in the Appalachian Basin will provide valuable information to assist producers in designing, modeling, and optimizing gas recovery.

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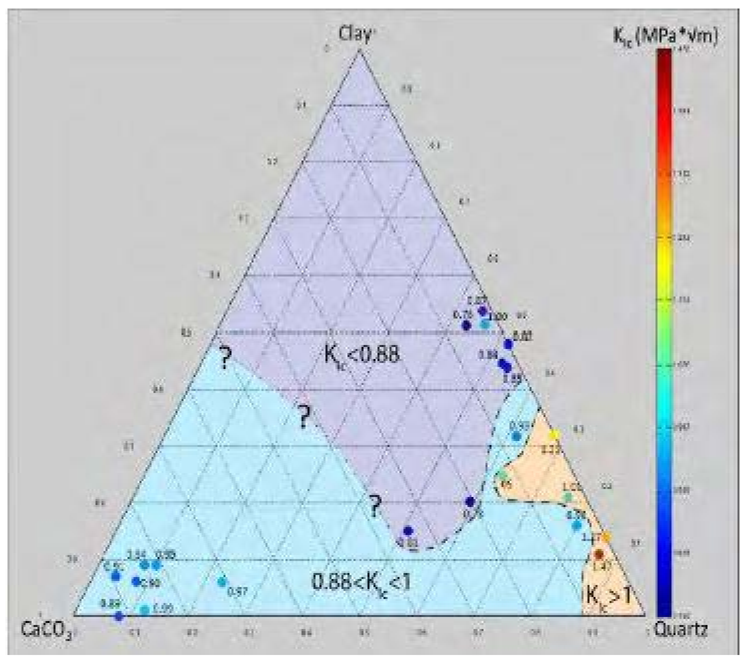
Project Number: 09122-32

This project is ongoing; therefore, the final report is not yet available. Additional details about this project are available through the RPSEA website at: http://www.rpsea.org/projects/09122-32/.



Ternary diagram depicting mineral composition (from XRD analysis) and fracture toughness magnitudes of the sampled intervals in this study.

Connectivity between Fractures and Pores in Hydrocarbon-rich Mudrocks—University of Texas at Austin; 6/2014-6/2016

Objective: This newly-started project aims to determine the degree to which fracture systems induced prior to production form a network of connected flow pathways that access the surrounding matrix porosity. The overall goal of this project is to develop methods for targeting the most potentially-productive regions of mudrock reservoirs and exploiting favorable rock properties to enhance production rates and recovery.

Research Planned: This project will include both laboratory experiments and numerical simulations to improve understanding of fracture system development and characterization. They will be measuring several parameters—including nuclear magnetic resonance (NMR) transverse relaxation (T_2)—to build a complete picture of fractures in mudrock. The researchers will be defining the rock properties and stress conditions necessary for fracture systems to develop, and characterizing the size and distribution of fracture systems that do develop. In addition, they will be characterizing the unfractured matrix microstructure around fractures. The researchers will use the findings from these characterizations and experiments to develop methods for optimizing production within mudrock reservoirs and enhancing production rates and recovery.

Results-to-Date: The researchers have begun the experimental phase of the project, including using mudrock samples to assess the change in pore space and opening of microcracks during deformation. The researchers have been conducting compressive strength testing of rock samples including measuring ultrasonic velocities. They are collecting a group of sub-samples from samples used in this initial testing; this group of sub-samples will undergo low-pressure gas adsorption testing.

Ongoing Activity and Future Plans: The researchers will be comparing seismic experimental results with both effective medium models and numerical simulations. They will be integrating and synthesizing the data as experimental and modeling results are produced. For example, they will be comparing microfracture development observed in images with NMR data, and comparing geophysical model results with acoustic measurements.

Benefits: At the conclusion of this project, researchers will have a clearer picture of how fracture systems form networks of connected flow pathways in mudrock reservoirs.

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Project Number: 12122-52

This project is ongoing; therefore, the final report is not yet available. Additional details about this project are available through the RPSEA website at: http://www.rpsea.org/projects/12122-52/.

Evaluation of Deep Subsurface Resistivity Imaging for Hydrofracture Monitoring—Groundmetrics, Inc.; 10/2013-9/2015

Objective: Hydraulic fracturing allows commercial gas production from unconventional formations; however, this method of production is more expensive than conventional methods and production is highly variable, often with the majority of gas or oil produced during only a few of the fracturing stages. Variable production often leads to more extensive fracturing operations than may really be necessary; as a result, excess proppant ends up being pumped into the formation. Currently, the eventual destination of the injected fluids used in reservoir stimulation is poorly understood. Seismic methods are used to locate hypocenters and produce images of entire fracture networks using the tomographic fracture image. The underlying data represent the fracture of the host rock.

In contrast, a novel method of Depth-to-Surface Electromagnetic (DSEM) imaging designed to image the presence of hydrofracturing fluid in the pore spaces should quantify the resulting increase in porosity. The objective of this project is to determine whether an in situ measurement of bulk electrical resistivity, using DSEM imaging, can be related to the changes in rock properties and fluid propagation that occur due to hydraulic fracturing. Electromagnetic data will be processed to quantify the EM signal and will be compared with simultaneously acquired micro-seismic data.

Research Planned: Researchers developed an approach to using tomographic fracture imaging data to project the fracture surface. They calculated the signal produced by a hydrofracture using an adapted version of a previously-published model, and completed initial testing of the new data collection hardware. The initial field testing occurred in the Anza Borrego Desert in southern California. Verification of the new 3D electromagnetic (EM) code was completed by comparing it to published solutions, including those for a split borehole casing communication system and to a 2D DC code that modeled a casing. Good agreement was seen for both comparisons. Operational improvements to receiver, data acquisition, and ancillary survey hardware were also successfully field tested at the California desert site.

Accomplishments: Researchers implemented a computer program to successfully calculate the electric field change at the surface caused by a fracture disturbing the subsurface distribution of electric current. The code is finite element, is 3D, and calculates the full electromagnetic (EM) solution. This is the first known code capable of incorporating the small scale of a borehole casing into a reservoir-scale model.

The study has also met its first milestone: the application of the novel 3D EM code to calculate the signature of a hydrofracture produced by current flow in layered earth, along a casing comprising a horizontal section connected to a vertical section. Researchers also made improvements to the data recorders, including adding a very high-precision internal voltage reference for in-field calibration, and simplifying all operating software to a single code module.

Ongoing Activity and Future Plans: Researchers will continue to fine-tune the code, models, and survey plan. An adaptation of a previously-published model was used to calculate the signal produced by a hydrofracture, and ongoing validation of that model will continue.

Lessons Learned: The original plan was to use four existing prototype recorders and 16 E-field sensors. Researchers learned that by delaying the test in order to develop and use new equipment, they were able to test more extensively and under more realistic conditions than they originally planned.

Benefits: If successful, this project will lead to reduced cost by reducing the number of fracture stages, and as a result, reducing the volume of fracture fluid required. This will also lead to improved gas recovery and environmental benefits over current methods. This research will also allow economic benefits to the public, including reduced energy costs and increased domestic economic activity.

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Project Number: FE0013902

This project is ongoing; therefore, the final report is not yet available. Additional details about this project are available through the NETL website at: http://www.netl.doe.gov/research/oil-and-gas/project-summaries/natural-gas-resources/fe0013902-groundmetrics

Fabry-Perot MEMS Accelerometers for Advanced Seismic Imaging—Lumedyne Technologies, Inc.; 10/2008-6/2015

Objective: Conventional geophone technology for seismic imaging provides a robust, reliable alternative that meets almost all requirements for seismic imaging; however, their narrow bandwidth and large size make them difficult to use in the field. Typical geophone diameters are approximately 1 inch before packaging, making them too large for easy deployment into new, smaller microholes. Further, the length of the geophones makes transportation of cabled geophones difficult as the rigid structure of the geophone causes stress on the cable connections when the cable is coiled, causing irreparable damage in the field. Lumedyne Technologies (LTI) proposes to resolve these issues by developing a seismic imaging accelerometer utilizing their patented optical transduction technique, with the ultimate goal of creating a small, rugged MEMS-based seismic imaging sensor that is sensitive to and has good signal-to-noise ratio at high frequencies (100 hertz to several kilohertz). LTI will be responsible for designing and protoyping the accelerometer and bringing the product to a commercial-ready state.

Research Conducted: LTI has designed, simulated, and fabricated the accelerometer and sensor; however, when they tested the fabricated system they observed an issue with the functionality of the manufactured components. Upon further review, the research team determined that the fabricated system did not meet the required specifications/tolerance and needed to be re-manufactured. LTI fabricated new accelerometer components, but they noted during testing that there are still inconsistencies in their manufacturing process. They have since made a technology breakthrough that could lead to a more simplified manufacturing process along with equal to better hardware performance.

Accomplishments: The LTI team has developed a small, rugged, composite accelerometer system. The package includes the MEMS sensor comprising the optical resonant cavity and silicon photodiode, a Vertical Cavity Surface Emitting Laser (VCSEL), integrated monitor photodiode for controlling the VCSEL power output, integrated focusing lens to increase power density and reduce packaging alignment requirements, optical isolator to prevent optical feedback into the VCSEL, and a micro-resistive heater for controlling the temperature of the VCSEL.

Ongoing Activity and Future Plans: Lumedyne has made a technology breakthrough that could lead to a better accelerometer. The benefits include improved low frequency response, lower power consumption, lower unit cost, and longer product life. LTI is moving forward to develop the accelerometer with plans being finalized for the time and location of a field study.

Lessons Learned: The operating principle of the accelerometer is based on a resonant optical cavity composed of two partially-reflective mirrors where the amount of light that passes through the cavity is dependent on the spacing between them; however, the current implementation resulted in formation of a secondary cavity between the moving mirror on the proof mass and the reflective surface of the emission point of the Vertical Cavity Surface Emitting Laser (VCSEL) that makes proof mass loop closure extremely difficult. Three light sources [the existing VCSEL, LEDs (Light Emitting Diodes), and RCLEDs (Resonant Cavity Light Emitting Diodes)] were evaluated to eliminate (or sufficiently control) the secondary cavity. RCLEDs were found to have the desired coherence length and eliminated formation of the secondary cavity.

Benefits: While improvements have been made in processing data to obtain sharper images of oil and gas reservoirs, higher resolution and real-time imaging are needed for accurate reservoir modeling. A key to obtaining high-resolution data is adequate bandwidth and signal-to-noise ratio, which requires that the sensors be placed over large areas (tens of square miles), or by placing them in boreholes. Successful development and widespread application of LTI's state-of-the-art seismic technology to image oil and gas reservoirs could result in a several-fold increase in domestic hydrocarbon production rates.

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Project Number: NT0005670

This project is ongoing; therefore, the final report is not yet available. Additional project details are available through the NETL website at: http://www.netl.doe.gov/kmd/cds/disk41/B%20-%20Reservoir%20Characterization/NT0005670%20fact%20sheet.pdf.

Evaluation of Fracture Systems and Stress Fields within the Marcellus Shale and Utica Shale and Characterization of Associated Water-Disposal Reservoirs: Appalachian Basin—University of Texas, Bureau of Economic Geology; 9/2009-11/2012

Objective: Traditionally, seismic studies of shale have focused on P-waves (i.e., seismic waves that propagate through a solid, liquid, or gas) rather than S-waves (i.e., shear waves). The main goal of this project was to demonstrate the value of expanding from strictly P-wave to multicomponent seismic technology for identifying unconventional resources.

Research Conducted: The researchers measured P- and S-waves generated from various sources, considered the merits of cable-free or cabled data recording systems, compared geophones to accelerometer sensors, developed models for how P- and S-waves would respond to orthorhombic media, tested that full elastic wavefields were created by vertical sources, and demonstrated that S-wave data could reveal important reservoir features that P-wave data could not.

Accomplishments: The researchers compared and documented the virtues of both cabled and cable-free recording systems and also geophones and accelerometer as seismic sensors. They collected and analyzed multicomponent seismic data from field testing; the wave data was generated by producing waves through various methods (including explosive, accelerated-weight impact, and vibratory energy sources).

Ongoing Activity and Future Plans: This project is complete, and no future activities are planned.

Lessons Learned: One major finding of the study was that converted-shear (P-SV) data provided much better vertical resolution in shale-gas systems than P-wave data; also, P-SV was a more-effective way to identify fractures. Hidden reservoir features (e.g., compartments) in Devonian sandstone that were not revealed in P-wave data were detected in the S-wave data.

Benefits: Geological information needed for optimal exploitation of the Marcellus Shale is defined in greater detail with P-SV seismic data than with P-P data. For example, P-SV data reveals anomalies that can indicate potential storage reservoirs. As demonstrated through this study, P-SV data provides a more complete picture of shale systems and can help operators more effectively identify these potential water-storage units.

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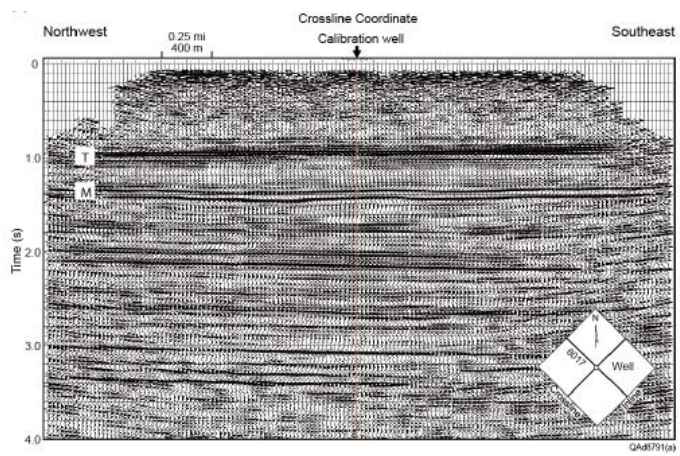

Vertical slices through P-SV volumes constructed from the 3C3D seismic research data.

Project Number: 08122-55

The final report for this project is available at: http://www.rpsea.org/media/files/project/ddc0ae3a/08122-55-FR-Evaluation_Fracture_Stress_Marcellus_Shale_Utica_Water_Disposal_Appalachian_Basin-01-01-13_P.pdf.

Prediction of Fault Reactivation in Hydraulic Fracturing of Horizontal Wells in Shale Gas Reservoirs—West Virginia University; 1/2011-1/2015

Objective: To capture hydrocarbons economically from within shale gas reservoirs, multi-stage hydraulic fracturing treatments are required to increase the shale rock flow network. This process involves using high pressure to inject fluids into the well, which generates stress in the shale and opens existing fractures or creates new ones. The resulting fractures redistribute stresses in the surrounding areas and may potentially reactivate nearby subsurface faults.

Because fault reactivation (shear slippage) may result in seismic activity, leakage of fracturing fluid, and early failure of the fracturing process, it is necessary to minimize the potential of fault reactivation for hydraulic fracturing in horizontal wells. Current technology does not allow for the prediction of potential fault reactivation induced by simultaneously propagating multiple fractures during the hydraulic fracturing process, and there is currently no mathematical model or tool available to aid in controlling the fracture propagation to avoid fault reactivation. Thus, researchers proposed to develop methods to characterize shale gas reservoirs and improve hydraulic fracturing simulations of horizontal shale gas wells under various reservoir and fault conditions. The ultimate goal of the research is to develop advanced technology to predict fault reactivation during and after hydraulic fracturing treatments and methods to optimize the design of the multiple perforation clusters (used to create multiple transverse fractures).

Research Conducted: Researchers collected well logs, core data, and seismic survey information from an area of the Marcellus shale play in the Appalachian Basin. With this field data, they evaluated the in-situ stress conditions of faults and identified critically-stressed faults near the wells in order to develop a three-dimensional (3D) boundary element model and a 3D geomechanical stress/displacement model. Because the orientation and relative magnitudes of stress fields vary and influence the direction of fracture propagation depending on faulting environments, researchers performed case studies simulating various conditions. In each study, three simultaneous hydraulic fractures were created under three different fault environments: normal, strike-slip, and strike-slip/reverse faults. Additonally, poroelastic effects were considered to investigate the influence of fracture locations on stress states along the fault plane and the optimal conditions of fracturing operations with regard to spacing between stages, fracture orientation of a subsequent stage, and related fault stability.

Accomplishments: In addition to developing and validating the WVUHF-2D simulator, researchers developed a coupled 3D simulator (WVUHF-3D) and a 3D fracturing propagation model using a finite element method with elastobrittle cohesive elements. The model was used to simulate the propagation of simultaneous multiple fractures in multi-layer reservoirs and to describe the dynamics of those fractures and the state of stresses in the surrounding regions in a 3D domain. Results of the simulations indicate that the angle between fracture orientation and fault strike strongly influences the stability of a fault based on the change in the ratio of stress types, and that the stress alteration patterns are different for each of the three types of fault. The normal faulting environment has the largest fluctuation in stresses and in the ratio of shear to effective normal stress, whereas the reverse/strike-slip fault has the least effect on stresses and the ratio of shear to effective normal stress during hydraulic fracturing.

Ongoing Activity and Future Plans: Researchers continue to develop 3D geomechanical stress/displacement and fracturing propagation models and validate the WVUHF-3D simulator. Ongoing characterization of the stress state of the study area is also being completed through modeling of heterogeneous distributions of stress field. As project activities advance allowing stress states and faults to be modeled in ever-more precise detail, the accuracy of fault reactivation predictions will increase.

Lessons Learned: Researchers learned that the shape of a fault's slip-tendency contour, as given by 3D numerical models, depend on the fault types. The unstable regions identified by numerical modeling can be interpreted as regions with improved permeability. Results also indicated that the numerical models used predominantly in the current literature to simulate hydraulic fracturing with fluid lag (the gap between the fracturing fluid front and the fracture tip) are different than those used for fracturing without fluid lag. As a result, the researchers proposed an implicit method for tracking the fluid front that eliminates the need to re-mesh models.

Prediction of Fault Reactivation in Hydraulic Fracturing of Horizontal Wells in Shale Gas Reservoirs—West Virginia University; 1/2011-1/2015

Benefits: This project provides insight about stress redistribution during hydraulic treatment and the impact of hydraulic fracturing on fault stability. The transformative tools that result from this research will advance precise modeling of shale gas reservoirs, allowing the reliable prediction of fault reactivation, the optimization of fracture design, and the management of fault stability through adjustments in those designs.

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Project Number: 09122-06

This project is ongoing; therefore the final report is not yet available. Additional project details are available through the RPSEA website at: http://www.rpsea.org/projects/09122-06/.

Task 6, Integrated Field Monitoring—NETL ORD

Objective: Hydraulic fracturing for natural gas extraction has increased the amount of natural gas available from U.S. shale gas resources. Although prior reports from industry show that fractures generated during hydraulic fracturing of Marcellus Shale remain thousands of feet below underground sources of drinking water, independent verifications of these observations are limited. The objectives of study are to determine the upward extent of the effects of hydraulic fracturing associated with six Marcellus Shale gas wells within a production pad in Greene County, Pennsylvania, and determine whether induced fractures in conjunction with natural fractures and existing well penetrations provide pathways for fluid and gas migration to overlying formations at that location.

Research Conducted: This task incorporates multiple field monitoring parameters into an integrated field campaign to identify cause-and-effect relationships during the development of unconventional oil and gas resources. This task is being performed at three established Marcellus Shale sites in southwestern and central Pennsylvania: the (1) Washington County site, (2) Greene County site, and (3) Clearfield County site. The study employed multiple lines of evidence to determine if fluids and gas from the hydraulically fractured Marcellus Shale had migrated at least 3,800 ft. upward to a monitored conventional gas reservoir in the Upper Devonian and Lower Mississippian reservoirs. This evidence was collected before, during, and after the hydraulic fracturing of six horizontal Marcellus Shale gas wells and included (1) microseismic determination of the uppermost extent of the stress regime created by hydraulic fracturing; (2) pressure and production histories of Upper Devonian/Lower Mississippian wells; (3) chemical and isotopic analysis of the gas produced by Upper Devonian/Lower Mississippian wells; (4) chemical and isotopic analysis of water produced from Upper Devonian/Lower Mississippian wells (where fluid samples were available); and (5) monitoring for perfluorocarbon tracers in gas produced from two Upper Devonian/Lower Mississippian wells. Seven vertical gas wells completed in multiple, thin sands 3,800–6,100 ft. above the six horizontal Marcellus Shale wells were monitored for tracer (carbon and hydrogen isotopes in the gas, strontium isotopes in the fluids), pressure, and production evidence that would indicate possible migration of fluid or gas upward from the hydraulically fractured shale formation below. Researchers also employed geophones deployed in nearby vertical Marcellus Shale wells to detect and locate microseismic events that occurred during hydraulic fracturing.

Accomplishments: A comparison of production and pressure records from Upper Devonian/Lower Mississippian wells collected weekly for one year after hydraulic fracturing with records collected for a three-year period before hydraulic fracturing did not reveal pressure or production increases that might indicate migration of gas from the over-pressured Marcellus Shale below. Isotopic analysis of gas and produced water from the Upper Devonian/Lower Mississippian wells did not detect the presence of gas or fluids from the Marcellus Shale. These lines of evidence indicated that there was no detectable migration of gas and fluids from the Marcellus Shale to the overlying Upper Devonian/Lower Mississippian gas field caused by open fractures or unplugged wells. Researchers found that under the conditions of this study, for this specific location, fracture growth ceased more than 5,000 feet below drinking water aquifers and there was no detectable upward migration of gas or fluids from the hydraulically fractured Marcellus Shale project.

Ongoing Activity and Future Plans: Samples of gas and produced water continue to be collected monthly (produced water) and bimonthly (gas) from seven Upper Devonian/Lower Mississippian gas wells.

Lessons Learned: The pressure differential between the Marcellus Shale and the Upper Devonian/Lower Mississippian reservoirs is at a maximum during hydraulic fracturing when high-pressure fluids are injected into the Marcellus Shale. After hydraulic fracturing, the pressure in the Marcellus Shale immediately begins to re-equilibrate to regional pressure gradient. Although pressure differential could provide the driving force for gas migration between the Marcellus Shale and the Upper Devonian/Lower Mississippian gas reservoirs, the permeability of natural and created pathways must be significantly increased for the gas migration to take place within the timeframe of this study. This study is looking for evidence of more rapid gas migration over a period of 12 months that might be attributable to man-made changes to the seal provided by intervening strata (e.g., well penetrations and/or induced fracturing).

Task 6, Integrated Field Monitoring—NETL ORD

Benefits: This successful project may improve our understanding of how hydraulic fracturing affects the migration of gas throughout unconventional reservoirs, potentially improving our ability to extract oil and gas resources and resolve environmental concerns regarding groundwater contamination and induced seismicity.

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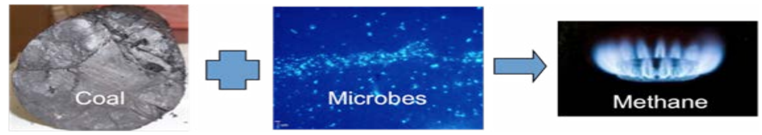
Biogeochemical Factors Enhancing Microbially Generated Methane in Coal Beds—Colorado School of Mines; 9/2008 – 6/2012

Objective: The collection of methane naturally generated in coal beds is a cleaner method of utilizing the energy provided by coal. Currently, methane generated in this manner supplies about six-percent of natural gas consumed in the U.S. The objective of this project is to investigate the biotic and abiotic factors that influence microbial transformation of coal in order to assess the potential for stimulating microbial methane production in situ.

Research Conducted: The research team studied and conducted experiments on various coal samples gathered from outcrops and coal seams in Colorado, Wyoming, and Nevada to identify chemical constituents of coal that are bioconverted and organisms associated with biogas generation from coal; characterize the influence of culture growth amendments and conditions on biogas generation; determine the effects of coal pre-treatment on levels of biogas precursor compounds, microbial communities, and ultimate methane generation; determine the rate limiting step(s) of microbial methane generation from coal; and capture chemical and microbial dynamics in a computer model for comparison purposes.

Accomplishments: The process by which microorganisms generate methane gas from coal is not well understood. Many steps and chemical substances are needed to complete this natural conversion. By systematically adding different substances to and removing them from this process, researchers determined which treatments gave the best results. In addition to studying naturally occurring processes, researchers used various coal pre-treatments. In total, five different treatments were tested to identify the potential for methane production. Only the addition of L-cysteine, an amino acid, produced methane. Acetate was also a key chemical identified in the process. Laboratory experiments demonstrated that methane gas production could be increased nearly five-fold by adding nutrients to stimulate the microorganisms in coal beds. In addition, methane can be produced without using excessive amounts of water. Some pretreatments, such as the use of nitric acid, also had a positive effect on the process.

Ongoing Activity and Future Plans: The project has been completed, and no further activities are planned.



Lessons Learned: The researchers determined that the coal samples used for the study were less than ideal. Future experiments need to consider coal integrity.

Benefits: Successful implementation of the findings could result in a large increase in cost-effective gas production combined with a reduction in risk to the environment.

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Project Number: 07122-14

The final report for this project is available at: http://www.rpsea.org/files/2876/.

Enhancing Appalachian Coal Bed Methane Extraction by Microwave-Induced Fractures—Penn State; 11/2008 – 5/2010

Objective: Methane is a naturally-occurring gas that is both a danger to coal miners and a viable source of energy. Releasing methane from coal seams is a slow process; a quicker, more efficient method is needed to remove this gas. The objective of this project is to determine the ability of microwave energy to create micro fractures in coal samples under simulated downhole conditions of pressure and temperature.

Research Conducted: Short bursts of microwave energy from an industrial X-ray CT scanner were applied to bituminous coal core samples taken from the Pittsburgh seam to determine whether methane could be removed from coal beds by using microwaves to create new fractures and expand existing cleats (fractures naturally found in coal). In this process, microwave energy heats the water within coal and forms steam that fractures it. The team examined both hydrostatically stressed and unstressed North American bituminous coal cores. The team used a microwave transparent argon gas pressurized (1000-psi) polycarbonate vessel to simulate hydrostatic stress at a depth of 1875 feet. They examined cleat frequency and distribution for two cores via micro-infused X-ray computed tomography, before and after microwave exposure, and with and without the application of hydrostatic stress. Optical microscopy was performed to examine the role of lithotypes in microwave fracturing.

Accomplishments: The project team conducted tests on both pressurized (simulating actual conditions) and unpressurized samples. Results demonstrated that the application of microwave energy succeeded in both creating fractures and expanding cleats. Researchers expected the fractures to occur vertically, but most fractures created in this manner were horizontal. Cleat expansion ranged from 100 to 400 percent. Samples subjected to pressure reacted similarly to those that were not, but fewer new fractures were created and the cleats expanded less.

Ongoing Activity and Future Plans: The project is complete and no further activities are planned.

Lessons Learned: Microwave energy has been used successfully by the coal industry to fracture coal before pulverizing for burning. The question of microwave energy accomplishing this under in-situ conditions of pressure and temperature were investigated. Results indicate feasibility, opening the way to future downhole tools that use microwave energy.

Benefits: Increasing the quantity of and speed at which methane gas is released from coal can help make coal mines safer and more cost-efficient.

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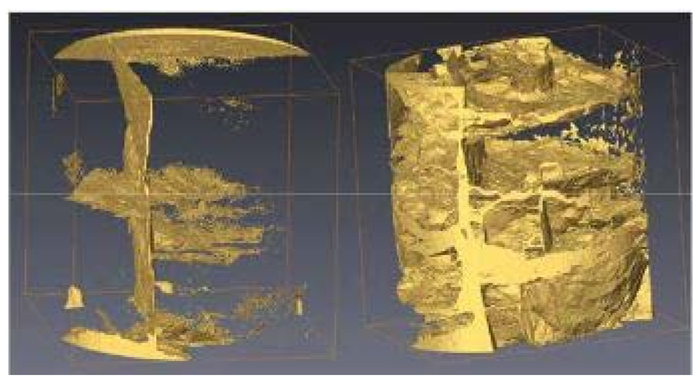
Project Number: 07122-27

The final report for this project is available at: http://www.rpsea.org/media/files/project/7e5570da/07122-27-FR-Enhancing_Appalachian_Coalbed_Methane_Extraction_Microwave_Induced_Fractures-08-23-10_P.pdf.



Fracture map of the unconfined coal core before (left) and after (right) microwave exposure.

Novel Concepts for Unconventional Gas Development in Shales, Tight Sands, and Coal Beds—Carter Technologies; 7/2008 – 2/2009

Objective: Current methods of horizontal drilling and fracturing can result in rapidly declining production and can leave as much as 90 percent of gas in place. The objective of this project was to develop novel concepts to cost-effectively stimulate gas production from low permeability rock, including shale, tight sands, and coalbed formations. A further objective was to maximize the total recovery of gas from a given area by accessing a larger percentage of the total reservoir volume. To this end, the researchers wanted to determine the feasibility of using a saw to cut a deep slot from a horizontal borehole into the formation at depths from 5000 to 10000 feet.

Research Conducted: The project team performed a technology status assessment to identify potentially useful drilling concepts. More than a dozen concepts were evaluated, including the use of jetting systems, rotating cutters, reciprocating cutters, cable saw systems, elastic cable stretch systems, pressure-driven auto-stroke cable saw systems, cable anchor-spring loaded systems, and various pipe-driven cable saw systems. Concepts were judged based on mechanical feasibility, mechanical robustness, cuttings management, cost, productivity, and overall reliability. The researchers selected a method for using a downhole cable saw to cut a pathway or "slot" into the formation all along the length of a horizontal well bore within a shale formation; this method could potentially reduce production decline and formation damage and enable recovery of a larger percentage of the in-place gas compared to conventional completions. This method uses cable attached to a special joint on a standard drill pipe to generate tension on the cable to create a uniform cut, better control the depth of the cut, and keep the cable from breaking or getting stuck.

Accomplishments: The research determined that this method is mechanically feasible. The project recipients are seeking a patent on the new method and have licensed it to a major oil and gas company. A computer model developed during the course of this project indicated that the deep horizontal slots produced by this method could produce 50 to 100 times as much surface area as a horizontal well alone.

Ongoing Activity and Future Plans: This project is complete and no further activities are planned.

Lessons Learned: The project included a specific task to evaluate the use of high-pressure water jets for cutting through rock. A tool previously developed by the principal investigator, called the "soil saw," used this technology to cut and form a 12-inch wide cutoff wall in soil at rates of up to 100 square feet per minute; however, studies concluding that the technology will not cut through rock as easily as soil and that many high-pressure pumps will be needed precluded further study.

Benefits: This method, if successful, would open up economic production in tight formations that do not respond to conventional hydraulic fracturing stimulation or for which there is insufficient data to design a fracturing treatment. This low capital cost method should be within the reach of small production companies, and since it does not require as much formation data to be successful, may prove attractive to wildcat operators, enabling the rapid development of new fields.

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Project Number: 07122-07

The final report for this project is available at: http://www.rpsea.org/files/2874/.

Optimizing Development Strategies to Increase Reserves in Unconventional Gas Reservoirs—Texas A&M; 8/2008 – 1/2012

Objective: Normal well operations begin with large well spacing and then decrease through trial and error. This adds to the risk and cost. It has taken decades to optimize spacing for some unconventional gas developments. In areas where there has been little exploration, there is not enough historical information available to determine well spacing. Development is too slow to meet demand. The objective of this research is to develop technology and tools to help operators quickly determine optimal well spacing and completion strategies in highly uncertain and risky unconventional gas reservoirs.

Research Conducted: Researchers integrated two models: a reservoir model based on simulation and a decision model that used decision trees. Data populating the models were initially based on the 46 existing vertical wells of the Berland River formation in southern Alberta. The modeling tools @Risk and IMEX were used for the Monte Carlo simulations. Researchers considered modeling the drilling of one, two, four, and eight wells in a 640-acre section for a period from one to five years with well spacing ranging from 40 to 640 acres. Researchers used single- and multi-well models. Different variables, such as production, porosity, permeability, depth, fracture, water saturation, and drainage area, were used in the simulations. Two different sets of well and production data were used to model oil production in the Barnett shale. These wells were horizontal wells with multiple hydraulic fractures. Researchers forecasted gas production from oil production data.

Accomplishments: Modeling a single-well in tight gas sands indicated that the optimal spacing is 160 acres with no downspacing in the second stage. The multi-well model was a better match to actual well production and produced the same predictive well spacing results as the single-well model; however, the multi-well model was more difficult and time-consuming to use. Results from the Barnett modeling demonstrated a correlation between the decrease in production (decline curve) and the intervals between horizontal well bore perforations. This project team developed three integrated modeling and decision-making tools: a decline-curve based reservoir model, single-well reservoir simulation model, and a multi-well simulation reservoir model. These models will help developers understand the uncertainty involved in drilling unconventional reservoirs and determine tradeoffs.

Ongoing Activity and Future Plans: This project is complete, and no further activities are planned.

Lessons Learned: It was not possible to develop an integrated one-size-fits-all reservoirs model; however, this project team developed a suite of integrated modeling and decision-making tools that can be tailored to specific reservoir and economic conditions. Economic data should be included in the model order to weigh the costs and benefits, making it more applicable in decision-making.

Benefits: By using the processes identified in this research, drillers can quickly reach optimal well spacing, which will increase the amount of gas produced. The methodologies developed in this project can—with minor changes—be applied to other unconventional reservoirs.

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Project Number: 07122-35

The final report for this project is available at: http://www.rpsea.org/files/1884/.

Optimization of Infill Well Locations in Wamsutter Field—University of Tulsa; 9/2008-9/2011

Objective: In order to increase the recovery of gas in fields, infill wells are placed in the spaces between existing wells. The objective of this project was to determine the appropriate well spacing in the tight gas reservoirs of the Wamsutter field in the Green River Basin of southwest Wyoming with the goal of maximizing gas recovery while minimizing the number of wells. The Wamsutter field is being developed with 80-acre spacing. Operators are considering 40-acre spacing in future work.

Research Conducted: Using log and production data from the existing 81 wells in the Wamsutter field, researchers developed a new method to determine the effectiveness of infill wells. The wells are in the Almond formation; 75 are vertical wells and six are deviated. Wells in the Lewis and Lance shale were not included because only a few are producing from those areas. Data captured included porosity, permeability, water saturation, and payload. A user-friendly program was developed to enable easy use of this methodology. Researchers also modeled and simulated well performance, testing its accuracy by matching it to historical production.

Accomplishments: Devon Energy, a subcontractor on this project, tested and validated the new program in the Wamsutter and Pinedale gas fields. Researchers used this program to determine the optimal location of infield wells. Devon Energy drilled seven new wells using the methods developed in this project, and the performance of the newly-drilled wells was compared to the predictions. Although the amount of information collected thus far is limited, in general, the performance of the newly-drilled wells is worse than the predictions. Matching the performance of the new wells to the simulation revealed significantly smaller fracture conductivity compared to the predictions. Because the wells are still young, time may provide a better measure of success. The operator has indicated that the performance of some wells continues to improve.

Ongoing Activity and Future Plans: This project is complete, and no future activities are planned.

Lessons Learned: Researchers found that they needed to include liquid loading into their model (an issue that affected many wells). Liquid loading is the accumulation of liquid at the bottom of the well that reduces permeability and can kill the wells. In the field, water in these wells was dealt with by installing plunger lift artificial systems. The use of these systems makes the flow discontinuous, which was difficult to reproduce in simulation. For the purpose of this project, researchers based the model on continuous production and accounted for the liquid loading by using the skin factor.

Benefits: Successful identification of locations for 40-acre spacing wells could increase the potential reserves of the Wamsutter field by as much as 40 percent. This model will help operators identify locations where no infill wells are needed to deplete the reservoir; fewer wells will mean lower cost. This research is also applicable to other tight gas sandstone reservoirs in the Rocky Mountain region and will aid in determining optimal well spacing.

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Project Number: 07122-43

The final report for this project is available at: http://www.rpsea.org/media/files/project/0a928246/07122-43-FR-Optimization_Infill_Well_Locations_Wamsutter-08-24-11_P.pdf.